IDENTIFICATION OF PROJECTS UNDER CLEAN DEVELOPMENT MECHANISM AND THEIR IMPACT ON GENERATION PLANNING OF INDIAN POWER SYSTEM

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by

SANKARA SRIKANTH

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CERTIFICATE

This is to certify that the work contained in this thesis entitled "**Identification of Projects under Clean Development Mechanism and their Impact on Generation Planning of Indian Power System**" has been carried out by Sankara Srikanth (Y3104083) under my supervision and that this work has not been submitted elsewhere for a degree.

April, 2005

Dr. S. C. Srivastava
Professor
Department of Electrical Engineering
Indian Institute of Technology,
Kanpur-208016

Dedicated

To

My beloved father Late S.V. Lakshmana Rao

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ABSTRACT

To meet the ever rising demand of electrical energy, most of the countries, including India, are going for large scale expansion of their power generation system, which is largely based on fossil fuels. The contribution of power plants in the emission of Green House Gases (GHGs) has been found to be significant. Thirty nine countries across the globe, under a United Nations Framework Convention on Climate Change (UNFCC), held in Kyoto in December 1997, decided to reduce their GHG emissions by an average of 5.2% of their base level emissions in the year 1990, during the first commitment period of 2008-2012. India has ratified the Kyoto Protocol and is categorized as a non Annex-I country, which does not have any emission caps at present. Various tools were proposed to assist these emission capped countries in achieving their emission targets, including Clean Development Mechanism (CDM). Since not much literature is available to identify and quantify the impact of CDM projects on the Indian power sector, this thesis presents a detailed study on this subject.

The present work quantifies various parameters associated with the generation expansion planning to identify the CDM projects using GHG emission reduction, total cost and Marginal Abatement Cost (MAC) as decision parameters. The utility, financial and environmental implications of the identified CDM options on the integrated Indian power system has been studied and analyzed. Sensitivity analyses of expansion costs and GHG emissions with respect to change in commitment year of CDM options have been presented. An Integrated Resource Planning Analyses (IRPA) package and CPLEX optimization software have been used for this purpose.

According to this study, Solar and BIGCC (Biomass Integrated Gasification Combined Cycle) technologies have been identified as candidate CDM options. However, an analysis of utility, cost and environmental implications of these candidate CDM technologies reveal that the BIGCC is a more promising technology under Clean Development Mechanism.

Chapter 1

Introduction

1.1 Background

Rapid industrial development requiring increased use of fossil fuels resulting in depletion of natural resources of energy and increased level of Green House Gas (GHG) emissions are some of the major concerns being faced by the world today. Carbon dioxide, Methane, Nitrous oxide, Sulphur hexafluoride, per fluorocarbons (PFCs) and hydro fluorocarbons (HFCs) are a few main green house gases. The increasing level of GHG emissions has already warmed the earth's atmosphere by 0.3 to 0.6.°C since 1860 and the last two decades have been the warmest [1]. The first world climate change conference in 1979 addressed, for the first time, the problem of climate change and GHG emissions. A number of conferences focusing on climate change issue were held during 1980s and early 1990s.

It was the United Nations Framework Convention on Climate Change (UNFCC) in 1992, which pioneered the task of stabilizing GHG emissions. According to the decision taken in the third Conference of Parties (CoP) held in Kyoto in 1997, also called the Kyoto Protocol, the developed countries will undertake an average reduction of 5.2% in GHG emissions between 2008 and 2012 relative to their 1990 levels. The individual targets of Annex-I parties (countries which have binding emission caps, also called Annex-B countries) were defined. The Kyoto Protocol has devised mechanisms like, Joint Implementation, Emissions Trading, and Clean Development Mechanism (CDM) for assisting the Annex-I countries in achieving their emission targets [2]. The Kyoto Protocol became a legally binding agreement to reduce greenhouse gases emissions world wide on 16^{th} February 2005. At this stage of negotiation, CDM appears to be the most important mechanism for both the Annex-I and non Annex-I (developing countries which do not have

binding emission caps). Under the CDM, the Annex-I countries will invest the capital in terms of efficient technologies or cost-effective technologies in non Annex-I countries, rather than in their home countries. The amount of GHG emissions reduced by the implementation of efficient technology will go to the credit of Annex-I countries which have invested the capital, as Certified Emission Reduction (CER) value [3]. Hence, the CDM projects may lead to transfer of efficient technologies and climate friendly technologies to the developing countries, in addition to helping the Annex-I countries in achieving their emission targets.

India is the world's fourth largest economy and has a fast growing energy market. India's current electric power generation falls 7.1% percent short of demand and peak load shortage of 12.1% in 2003-04 [4]. Coal is the primary source for its commercial energy needs. Coal is used for approximately 62.3% of India's electric power generation; oil and gas account for 10.2% [5]. High ash content in Indian coal and inefficient combustion technologies further contribute to India's emission of air particulate matter and other trace gases, including greenhouse gases. The total CO_2 emissions from thermal power plants in India stands at 1,081,440 tons per day, while the average CO_2 emission per unit of electricity is estimated to be 991 gm/kWh [6].

India has ratified the Kyoto Protocol on 26th August 2002. Being a non Annex-I country, India is not required to take on the reduction commitments right away. The ratification, however, is perceived as a commitment to the cause of environment. Various studies have concluded that India is likely to be one of the major countries supplying such projects [7]. At present, only a few developing countries are in advanced stages of CDM approval institution and project development. The CDM project development process in India picked up in early 2002, when the Netherlands government tender CERUPT was announced [8]. Given the present scenario of GHG emissions, India should embark on a CDM strategy that calls for more investment in the electric power generation sector.

1.2 State-of-the-Art

The emission of Green House Gases (GHG) and global warming associated with it has made environmental issues to be discussed in the recent literature. The power sector has been reported to be one of the main contributors of GHG emissions in many countries in Asia. As of 1999, the share of power sector in total CO_2 emissions was estimated to be 45.6% in India, 41.9% in China and 33.6% in Thailand [9].

Electricity generation in Asia, as a whole, is expected to increase at a higher rate than the global average. The share of thermal power generation is also likely to increase, given the expected growth of electricity generation in this region. Looking at the present trend, the share of thermal electricity generation is expected to increase to 81% in 2010 in case of India [10]. As on 31st March 2004, out of a total installed capacity of 112683.47 MW, 80688.53 MW is the total thermal power installed capacity [5]. Coal based plants share the major part of the power produced in India as it has large reserves of coal.

The coal-fired plants are a major source of GHG emissions. According to a World Bank report, CO_2 emissions in India by the year 2015 will be 775 million metric tons per year, as compared with 1000 million metric tons per year in 1999 produced by the entire European Union. It also expects that SO_2 and NO_X production will be at three times the current levels [11]. From a global perspective, India will account for 18% of the increase in CO_2 emissions produced from energy use in developing countries between 1985 and 2025 [12]. Hence, it has become mandatory to explore all the options while bringing the emissions of pollutants within a target set [13].

The impact of IPPs and DPG and on environmental emissions and utility planning in Northern Region Electricity Board (NREB), India was extensively studied in [14]. The impact of carbon and energy taxes on environmental emissions and expansion planning of NREB system and integrated Indian power system has been presented in [15,16]. One of the more recent options for bringing down the emissions of pollutants can be through Clean Development Mechanism (CDM). The identification of CDM projects and the assessment

of their GHG and other harmful emissions mitigation potential for the case of NREB has been studied in [17,18]. In this study, it has been concluded that BIGCC in Traditional Resource Planning (TRP) baseline and Nuclear in Integrated Resource Planning (IRP) baseline are the most promising CDM projects.

A methodology for identification of CDM projects has been proposed in [18]. The methodology makes use of the least cost generation expansion planning study. Several models for long term generation expansion planning of power systems exist such as WASP, DECADES, PROSCREEN II, EGEAS, EFOM, MARKAL, etc. At present in India, CEA is using Electric Generation Expansion Analysis Systems (EGEAS) and Integrated System Planning Model (ISPLAN) models for long term power generation expansion planning. The EGEAS model, being a probabilistic model, provides for long range expansion planning as it yields very useful quantitative measures of reliability of power supply in the future years and gives the total cost of operating the existing and committed system and installing and operating the new systems. The transportation of fuel and transmission of power are not considered in the EGEAS model, but considered in the ISPLAN model. The ISPLAN model is a deterministic model [20]. But, the above said models do not incorporate the option of considering CDM options in the generation expansion planning. An IRPA (Integrated Resource Planning Analyses) package developed at the Asian Institute of Technology incorporates the option of considering CDM options in the generation expansion planning [21].

Various efficient supply side and demand side options for GHG emission mitigation from an Integrated Resource Planning perspective have been discussed in detail in [22]. The supply side options may include clean coal technologies like Integrated Gasification Combined Cycle (IGCC), Pressurized Fluidized Bed Combustion (PFBC), and Biomass Integrated Gasification Combined Cycle (BIGCC) and renewable energy resources like Wind and Solar. Demand side management options may include replacement of GLS lamps [31] with Compact Flouroscent Lamps (CFLs). Limited DSM data for the residential sector is derived from different available literature [29]. The chronological load curve for the agricultural sector is presented in a TERI report based on study done in Uttar Pradesh [32].

The method for calculating the Marginal Abatement Cost (MAC), which is one the decision parameter in identifying the CDMs is explained by Maya and Fenhann in [24]. Marginal Abatement Curves (MACs) may be used heuristically to demonstrate the advantages of emission trading and CDM. The MAC calculation methodology suggested in [27] can be useful in examining the implications of emissions trading for various trading scenarios involving, Annex B market, OECD market, full global trading.

1.3 Motivation

Emissions of Green House Gases and other pollutants from the power sector and its firmly established link with global warming and environmental pollution has made this issue to be discussed at various platforms in the recent past. It has become a major concern all over the world to put a cap on the emissions from the power sector. The evolution of Kyoto Protocol is a huge leap in this direction. Many of the developed countries have accepted the Kyoto Protocol and started an attempt to stabilize the GHG emissions. Emissions in the developing countries are also increasing rapidly as the power sector is expanding at a much faster rate to meet their economic growth. Hence, it has become a moral obligation for developing countries also to take some fast actions for the abatement of greenhouse gases.

Indian power sector which accounts for a major share in its total GHG emissions, is mainly fossil fuel dependent. There are various policy options available to reduce GHG emissions from Indian power sector such as increasing thermal efficiency, fuel switching, adopting clean coal technologies, utilizing efficient electric appliances (DSM), and reducing T&D losses. But the hurdle for implementing these policy options is lack of financial support as India is a developing country.

Given the present scenario of the GHG emissions from the Indian power sector and the advantages of CDM, the Indian Government has ratified the Kyoto Protocol in August 2002 and has decided to utilize the process of CDM initially in the power sector.

Since then, the Government of India has embarked on studying the impact of CDM on the Indian power system. Indian power sector is also strengthening its national grid interconnection to take advantage of the diversity of resources available for power generation in the county. This will also require changing into present generation expansion planning strategy at the regimal levels to an integrated national level planning.

From the literature survey, it appears that a systematic study on identifying the CDM projects, specifically for the integrated Indian power system network has not been carried out. Hence, the main motivations for the present study have been the following:

1) Identification of the plants which could be selected as the CDM options in the generation expansion planning scenario without DSM options known as Traditional Resource Planning (TRP) and also with DSM options considered known as Integrated Resource Planning (IRP) baseline.
2) To assess the potential of the identified CDM options in mitigation of GHG emissions and to study their utility and financial implications.
3) To identify the CDM projects with respect to various global trading scenarios, considering MAC as the decision parameter.

1.4 Thesis Organization

The work carried out in this thesis has been presented in four chapters. The present chapter discusses the importance of mitigating the GHG emissions from the electric power sector and briefly introduces the Clean Development Mechanism (CDM). It presents a representative state-of-the-art survey on the subject and sets the motivation behind the studies carried out in this thesis.

Chapter 2 describes in detail the methodology for identifying plausible CDM projects for the Indian power system, using the Integrated Resource Planning Analysis approach. The methodology for analyzing the utility, financial and environmental impacts

of CDM on the Indian power system has also been presented. An overview of the integrated Indian power system along with the input data and assumptions made in the analysis has been presented.

Chapter 3 provides the least cost generation expansion planning results under TRP and IRP baselines. Based on the results obtained, the plausible CDM options have been identified and their utility, financial and environmental implications have been studied. After analyzing the economics of CDM options, various trading scenarios with the Annex-I countries which can trade under the CDM, have been studied to identify CDM projects.

Chapter 4 concludes the main findings of the work and suggests scope for future research in this area.

Chapter 2

Methodology and System Data

2.1 Introduction

The objective of identifying projects under Clean Development Mechanism (CDM) requires performing least cost generation expansion planning studies. The least cost generation expansion planning determines the minimum-cost capacity addition plan (i.e., the type and number of candidate power plants) that meets the forecasted demand within a pre-specified reliability criterion over a planning horizon. The cost factor includes the capital investment cost and the power generation cost. Capital investment cost represents the total capital outlay necessary to build a power plant. Power generation cost includes the fuel cost, the fixed operating and maintenance cost and variable operating and maintenance cost. Different types of fuels considered in this study are coal, gas, oil, lignite and nuclear fuels. Coal is further categorized into twelve types according to their calorific value, cost and different process required for the combustion of the fuel.

The present study is also aimed at providing valuable insight in to the cost-effective technologies available for GHG mitigation, which need to be adopted in the power generation expansion planning. Role of supply side options in mitigating GHG emissions for the Indian power system has been analyzed. In supply side options, Pressurized and Fluidized Bed Combustion (PFBC) and Integrated Gasification Combined Cycle (IGCC) are taken as clean coal technologies, whereas Wind, Solar and Biomass Integrated Gasification Combined Cycle (BIGCC) plants are taken as renewable technologies. The demand side options considered for the study are replacing the GLS lamps [29] in residential sector with energy efficient CFL lamps [31] and rectification of agricultural pumps [32]. Study covers utility planning implications, cost and pricing implications, environmental implications under Traditional Resource Planning (TRP) and Integrated

Resource Planning (IRP) cases. Study is limited to a planning horizon of 20 years viz. from 2006 to 2025. The present chapter describes the mathematical formulation of the generation expansion planning problem along with methodology for identifying CDM projects and the data of integrated Indian power sector used in the study. Integrated Resource Planning Analyses (IRPA) package developed by [21] AIT and CPLEX software [23] has been used for solving this Multi Integer Programming problem which in turn gives the least cost generation expansion plan.

2.2 Mathematical Formulation of the Generation Expansion Planning Problem:

Integrated Resource Planning Analyses (IRPA) is a least cost generation expansion planning model which computes the total cost, including installation cost, operation and maintenance (O&M) cost and fuel cost. The IRPA also computes the emission levels of different pollutants and determines the optimal schedule for new capacity addition.

2.2.1 Objective function

The least cost generation expansion planning minimizes the total cost of candidate power plants and the cost of power generation from the existing and candidate power plants over the complete planning horizon. Mathematically, the objective of the least cost generation expansion plan is to:

Minimize

$$\sum_{j=1}^{J}\sum_{v=1}^{T}\left(C_{jv}+G_{jv}-W_{jv}\right)Y_{jv}+\sum_{m=1}^{M}\sum_{v=1}^{T}\left(CP_{mv}-WP_{mv}\right)YP_{mv}+$$

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=1}^{t}\sum_{j=1}^{J}\left(U_{jpstv}\cdot F_{jpstv}\cdot N_{st}\cdot\theta_{pst}\right)+\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=-V}^{t}\sum_{j=1}^{J}\left(U_{kpstv}\cdot F_{kpstv}\cdot N_{st}\cdot\theta_{pst}\right)+$$

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=1}^{t}\sum_{m=1}^{M}\left(UP_{mpstv}\cdot FP_{mpstv}\cdot N_{st}\cdot\theta_{pst}\right)+\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=-V}^{t}\sum_{n=1}^{N}\left(UP_{npstv}\cdot FP_{npstv}\cdot N_{st}\cdot\theta_{pst}\right)+$$

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=1}^{t}\sum_{m=1}^{M}\left(QP_{mpstv}\cdot FQ_{mpstv}\cdot N_{st}\cdot\theta_{pst}\right)+\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=-V}^{t}\sum_{n=1}^{N}\left(QP_{npstv}\cdot FQ_{npstv}\cdot N_{st}\cdot\theta_{pst}\right)+$$

$$\sum_{i=1}^{I}\sum_{r=1}^{R}\sum_{t=1}^{T}(D_{in}\cdot Z_{in})+\sum_{l=1}^{L}\sum_{p=1}^{P}\sum_{s=1}^{S}\sum_{t=1}^{T}\left(X_{lpst}\cdot H_{lpst}\cdot N_{st}\cdot\theta_{pst}\right)$$

where,

C_{jv} : Discounted capital cost of candidate power plant 'j' to be commissioned in vintage 'v'.

G_{jv} : Discounted cost of installing emission control devices in power plant 'j', to be year 'v'.

W_{jv} : Discounted salvage cost of power plant 'j', commissioned in year 'v' after time horizon 'T'.

Y_{jv} : Number of power plants of type 'j' installed in year 'v' (An integer variable).

CP_{mv} : Discounted capital cost of candidate power plant 'j', to be commissioned in vintage 'v'.

WP_{mv} : Discounted salvage value of pump storage hydro power plant 'm', commissioned in year 'v' after time horizon 'T'.

YP_{mv} : Number of pump storage hydro plants of type 'm' installed in year 'v' (An integer variable).

U_{jpstv} : Power generation of candidate power plant 'j' of vintage 'v' in block 'p' of season 's' in year 't'.

F_{jpstv} : Cost of per unit power generation from candidate power plant 'j' of vintage 'v' in block 'p' of season 's' in year 't'.

N_{st} : Number of days' in season 's' of year 't'.

θ_{st} : Width of block 'p' of chronological load curve of season 's' of year 't'.

U_{kpstv} : Power generation from plant 'k' of vintage 'v' in block 'p' of season 's' in year 't'.

F_{kpstv} : Cost of per unit power generation from existing or committed power plant 'k' of vintage 'v' in block 'p' of season 's' in year 't'.

UP_{mpstv} : Power generation from candidate pump storage hydro power plant 'm' of vintage 'v' in block 'p' of season 's' in year 't'.

FP_{mpstv} : Cost of per unit power generation from candidate pump storage hydro power plant 'm' of vintage 'v' in block 'p' of season 's' in year 't'.

2.2.2 Constraints

(a) Demand constraints:

This constraint requires that the total generation in each block of the planning horizon, from candidate and existing plants, will be more than or equal to the power demand during the planning horizon. Mathematically, the demand constraints can be formulated as follows:

$$\sum_{v=1}^{t}\sum_{j=1}^{J}U_{jpstv}\cdot\left(1-M_{jpst}\right)+\sum_{v=-V}^{t}\sum_{k=1}^{K}U_{kpstv}\cdot\left(1-M_{kpst}\right)+\sum_{v=1}^{t}\sum_{m=1}^{M}UP_{mpstv}\cdot\left(1-M_{mpst}\right)+$$
$$\sum_{v=-V}^{t}\sum_{n=1}^{N}UP_{npstv}\cdot\left(1-M_{npst}\right)-\sum_{v=1}^{t}\sum_{m=1}^{M}QP_{mpstv}-\sum_{v=-V}^{t}\sum_{n=1}^{N}QP_{npstv}+$$
$$\sum_{i=1}^{I}\sum_{r=1}^{R}\left[\left\{\sum_{t=1}^{t}Z_{irt}-\sum_{t=1}^{t-1}Z_{irt}^{'}\right\}\cdot P_{irps}\cdot E_{irpst}/\left(1-O_{rpst}\right)\right]+\sum_{l=1}^{L}X_{lpst}\geq Q_{pst}$$

for all ‘p’, ‘s’, ‘t’.

where,

M_{jpst} : Transmission loss in transmitting power from candidate generating station ‘j’ to load center in block ‘p’ of season ‘s’ in year ‘t’.

M_{kpst} : Transmission loss in transmitting power from existing generating station ‘k’ to load center in block ‘p’ of season ‘s’ in year ‘t’.

M_{mpst} : Transmission loss in transmitting power from candidate pump storage hydro power plant ‘m’ to load center in block ‘p’ of season ‘s’ in year ‘t’.

M_{npst} : Transmission loss in transmitting power from candidate pump storage hydro power plant ‘n’ in block ‘p’ of season ‘s’ in year ‘t’.

$Z_{irt}^{'}$: Number of efficient appliances retired in year‘t’ under DSM program ‘i’ by consumer category ‘r’.

P_{irps} : Power savings by efficient appliance under DSM program ‘i’ for consumer type ‘r’ in block ‘p’ of season ‘s’.

E_{irpst} : A fraction of the total installed appliances in use under DSM program ‘i’ for consumer type ‘r’ during period ‘p’ of season ‘s’ in year ‘t’.

O_{rpst} : Distribution loss for distributing power among consumer group 'r' in block 'p' of season 's' in year 't'.

Q_{pst} : Power demand in block 'p' of season 's' in year 't'.

(b) Plant availability constraints:

The power generation of each plant is limited by the capacity and availability of the plant in each period of the day. This constraint also takes into account the maximum limit on power import. Mathematically, the plant availability constraints can be formulated as follows:

$$U_{jpstv} \leq Y_{jv} \cdot a_{jv} \cdot B_{jv} \qquad \text{for all 'j', 'v', 'p', 's', 't'.}$$

$$U_{kpstv} \leq a_{kv} \cdot B_{kv} \qquad \text{for all 'k', 'v', 'p', 's', 't'.}$$

$$UP_{mpstv} \leq YP_{mv} \cdot ap_{mv} \cdot BP_{mv} \qquad \text{for all 'm', 'v', 'p', 's', 't'.}$$

$$UP_{npstv} \leq ap_{nv} \cdot BP_{nv} \qquad \text{for all 'n', 'v', 'p', 's', 't'.}$$

$$QP_{mpstv} \leq YP_{mv} \cdot aq_{mv} \cdot BQ_{mv} \qquad \text{for all 'm', 'v', 'p', 's', 't'.}$$

$$QP_{npstv} \leq ap_{nv} \cdot BQ_{nv} \qquad \text{for all 'n', 'v', 'p', 's', 't'.}$$

where,

a_{kv} : Availability of candidate power plant 'j' of vintage 'v'.

B_{jv} : Maximum capacity of candidate power plant 'j' of vintage 'v'.

a_{kv} : Availability of existing or committed power plant 'k' of vintage 'v'.

B_{kv} : Maximum capacity of existing or committed power plant 'k' of vintage 'v'.

YP_{mv} : Number of pump storage hydro power plants of type 'm' installed in year 'v' (An integer variable).

ap_{mv} : Generation availability of candidate pump storage hydro power plant 'm' of vintage 'v'.

BP_{mv} : Maximum generation capacity of candidate pump storage hydro power plant 'm' of vintage 'v'.

ap_{nv} : Generation availability of existing or committed pump storage hydro power plant 'n' of vintage 'v'.

BP_{nv} : Maximum generation capacity of existing or committed pump storage hydro power plant 'n' of vintage 'v'.

aq_{nv} : Pumping availability of candidate pump storage hydro power plant 'm' of vintage 'v'.

BQ_{mv} : Maximum pumping capacity of candidate pump storage hydro power plant 'm' of vintage 'v'.

BQ_{nv} : Maximum pumping capacity of existing or committed pump storage hydro power plant 'n' of vintage 'v'.

(c) Reliability Constraints:

The reliability of the power system is specified by setting up a reserve margin. Reliability constraints are defined in such a way that the total capacity of the plants and power generation avoided by efficient appliances should be greater than or equal to the peak demand plus the reserve margin in each year of the planning horizon.

$$\sum_{k=1}^{K}\sum_{v=-V}^{t} B_{kv}\left(1-M_{kp^*st}\right)+\sum_{j=1}^{J}\sum_{v=1}^{t} Y_{jv}\cdot B_{jv}\cdot\left(1-M_{jp^*st}\right)+\sum_{n=1}^{N}\sum_{v=-V}^{t} BP_{nv}\left(1-M_{np^*st}\right)+$$

$$\sum_{m=1}^{M}\sum_{v=1}^{t} YP_{mv}\cdot BP_{mv}\left(1-M_{mp^*st}\right)+\sum_{i=1}^{I}\sum_{r=1}^{R}\left[\left(\sum_{t=1}^{t} Z_{irp}-\sum_{t=1}^{t-1} Z'_{irp}\right)\cdot P_{irp^*s}\cdot E_{irp^*st}/\left(1-O_{rp^*st}\right)\right]+\sum_{l=1}^{L} X_{lp^*st}$$

$$\geq Q_{p^*st}\left(1+rm\right) \qquad \text{for all 't', 's'.}$$

where, p^* represents the peak load.

(d) Annual energy constraints:

Annual energy constraints are defined to limit the energy generation of each thermal plant according to the capacity, availability and time required for scheduled maintenance of the plant. Mathematically, the annual energy constraints may be modeled as:

$$\sum_{p=1}^{P}\sum_{s=1}^{S} U_{jpstv} \cdot \theta_{pst} \cdot N_{st} \quad \leq \quad \left(8760 - m_{jv}\right) \cdot B_{jv} \cdot Y_{jv} \qquad \text{for all 'j', 'v', 't'.}$$

$$\sum_{p=1}^{P}\sum_{s=1}^{S} U_{kpstv} \cdot \theta_{pst} \cdot N_{st} \quad \leq \quad \left(8760 - m_{kv}\right) \cdot B_{kv} \qquad \text{for all 'j', 'v', 't'.}$$

where,

m_{jv} : Scheduled maintenance hours/year of candidate power plant 'j' of vintage 'v'.

m_{kv} : Scheduled maintenance hours/year of existing or committed plant 'k' of vintage 'v'.

(e) Hydro energy availability constraints:

Hydro energy availability constraints are defined for each hydro plant such that its total energy output in each season should not exceed the pre-specified energy limit. Mathematically, the hydro energy availability constraints can be formulated as:

$$\sum_{p=1}^{P}\left(U_{jpstv} \cdot \theta_{pst}\right) \cdot N_{st} \quad \leq \quad \pi_{jstv} \qquad \text{for all 'j', 's', 't', 'v'. (j= Hydro plants)}$$

$$\sum_{p=1}^{P}\left(U_{kpstv} \cdot \theta_{pst}\right) \cdot N_{st} \quad \leq \quad \pi_{kstv} \qquad \text{for all 'k', 's', 't', 'v'. (k= Hydro plants)}$$

$$\sum_{p=1}^{P}\left(U_{jpstv} \cdot \theta_{pst}\right) \cdot N_{st} - \sum_{p=1}^{P}\left(QP_{mpstv} \cdot \theta_{pst} \cdot efp_{mv}\right) \cdot N_{st} \leq \pi p_{mstv} \qquad \text{for all 'm', 's', 't', 'v'.}$$

$$\sum_{p=1}^{P}\left(U_{npstv} \cdot \theta_{pst}\right) \cdot N_{st} - \sum_{p=1}^{P}\left(QP_{npstv} \cdot \theta_{pst} \cdot efp_{nv}\right) \cdot N_{st} \leq \pi p_{nstv} \qquad \text{for all 'n', 's', 't', 'v'.}$$

where,

π_{st} : Hydro energy available at hydro plant 'j' of vintage 'v', in season 's' of year 't'.

π_{kstv} : Hydro energy available at hydro plant 'k' of vintage 'v', in season 's' of year 't'.

efp_{mv} : Efficiency of candidate pump storage plant 'm' in vintage 'v'.

efp_{nv} : Efficiency of existing or committed pump storage plant 'n' in vintage 'v'.

πp_{mstv} : Hydro energy available at candidate pump storage hydro power plant 'm' of vintage 'v', in season 's' of year 't'.

πp_{nstv} : Hydro energy available at existing or committed pump storage hydro power plant 'n' of vintage 'v', in season 's' of year 't'.

(f) Fuel or resource availability constraints:

The fuel or resource availability constraints are defined to limit the energy generation of plants by particular fuel types if such limitations exist during the planning horizon. Mathematically, the fuel or resource availability constraints can be modeled as:

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=-V}^{t}\gamma_{kv}\cdot U_{kpstv}\cdot\theta_{pst}\cdot N_{st}+\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=1}^{t}\gamma_{jv}\cdot U_{jpstv}\cdot\theta_{pst}\cdot N_{st}\leq X_{j\max}$$

for all 'j', 'k' and same type of plants.

where,

X_{jmax} : Maximum resource availability for plant type j.

(g) DSM constraints:

These constraints are defined by the penetration rates of various DSM programs. Mathematically the DSM constraints can be modeled as follows:

$$\sum_{t=1}^{t} Z_{irt}-\sum_{t=1}^{t-1} Z_{irt} \quad \leq \quad A_{irt} * \beta_{irt} \qquad \text{for all 'i', 'r', 't'.}$$

where,

A_{irt} : Maximum appliances population under DSM program 'i' among 'r' type of consumer in year't'.

β_{rt} : Penetration rate of DSM program 'i' for consumer type 'r' in year 't'.

2.3 Methodology for Identification of CDM Projects in the Power Sector and Assessment of their GHG Emission Mitigation Potential

The basic analytical framework for the identification of a power sector project for implementation under CDM involves a least cost generation expansion planning model. The Integrated Resource Planning framework, as formulated in section 2.2 has been used to calculate the GHG emission with and without committing the candidate CDM options following the procedure given below for the two broad cases: a) Traditional Resource Planning (TRP) i.e., without DSM and b) Integrated Resource Planning (IRP) i.e., with DSM as illustrated in Figure 2.1.

1) Firstly, the least cost generation expansion plan is carried out for base cases of both TRP and IRP. The plants which are not selected in the base case during the planning horizon are taken as the plausible CDM projects for the analyses.
2) In the next step, the plants identified in step 1 are committed and the least cost generation expansion plan is carried out. The following conditions have to be satisfied: $E_{CDM}(CO_2) < E_0(CO_2)$ and $TC_{CDM} > TC_0$
   where, the quantities $E_{CDM}(CO_2)$ and TC_{CDM} refer to the total CO_2 emissions and the total generation expansion planning cost in the case when the candidate CDM is committed and the quantities $E_0(CO_2)$ and TC_0 refer to the total CO_2 and the total generation expansion planning cost in the base case. These conditions ensure that the CDM project when committed reduces GHG emissions (CO_2 in the present study), but, in conventional planning scenario, these are not selected due to their high cost.
3) From the results, one can calculate the Marginal Abatement Costs (MAC_{CDM}) for each of the CDM options using the formula described in section 2.6.3.
4) Compare the MAC of each CDM candidate plant with those in the developed countries. For this purpose, Marginal Abatement Cost of the developed countries was taken from [27] as shown in Tables 3.16 and 3.17 in the next chapter. If the MAC_{CDM} of a particular CDM candidate is found to be less than $MAC_{Annex\text{-}I}$, this candidate should be identified as the selected CDM project against trading with a

particular country or countries. The flow chart of the methodology is presented in Figures 2.1 and 2.2.

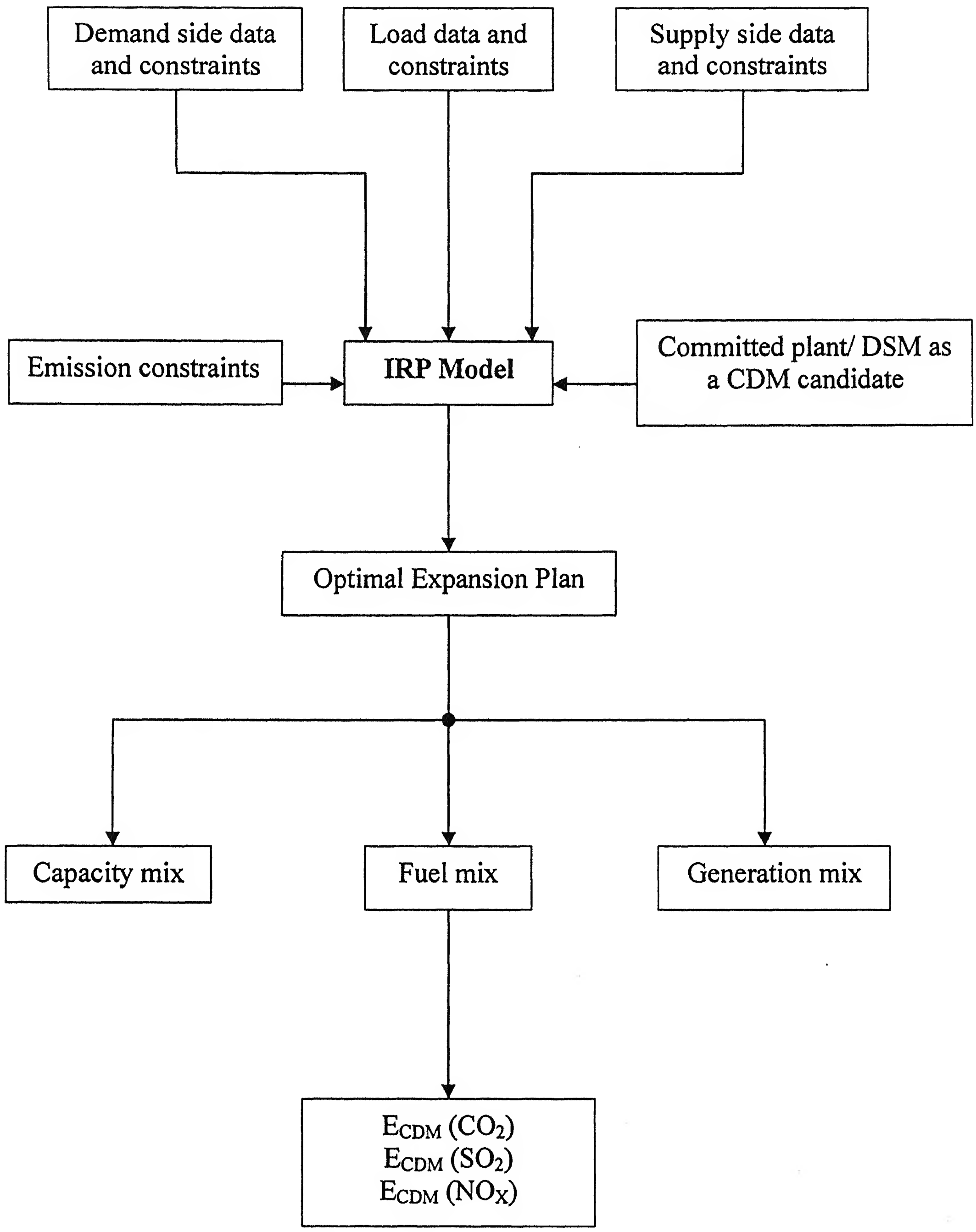

Figure 2.1: Calculation of GHG Emission Level with CDM Candidate

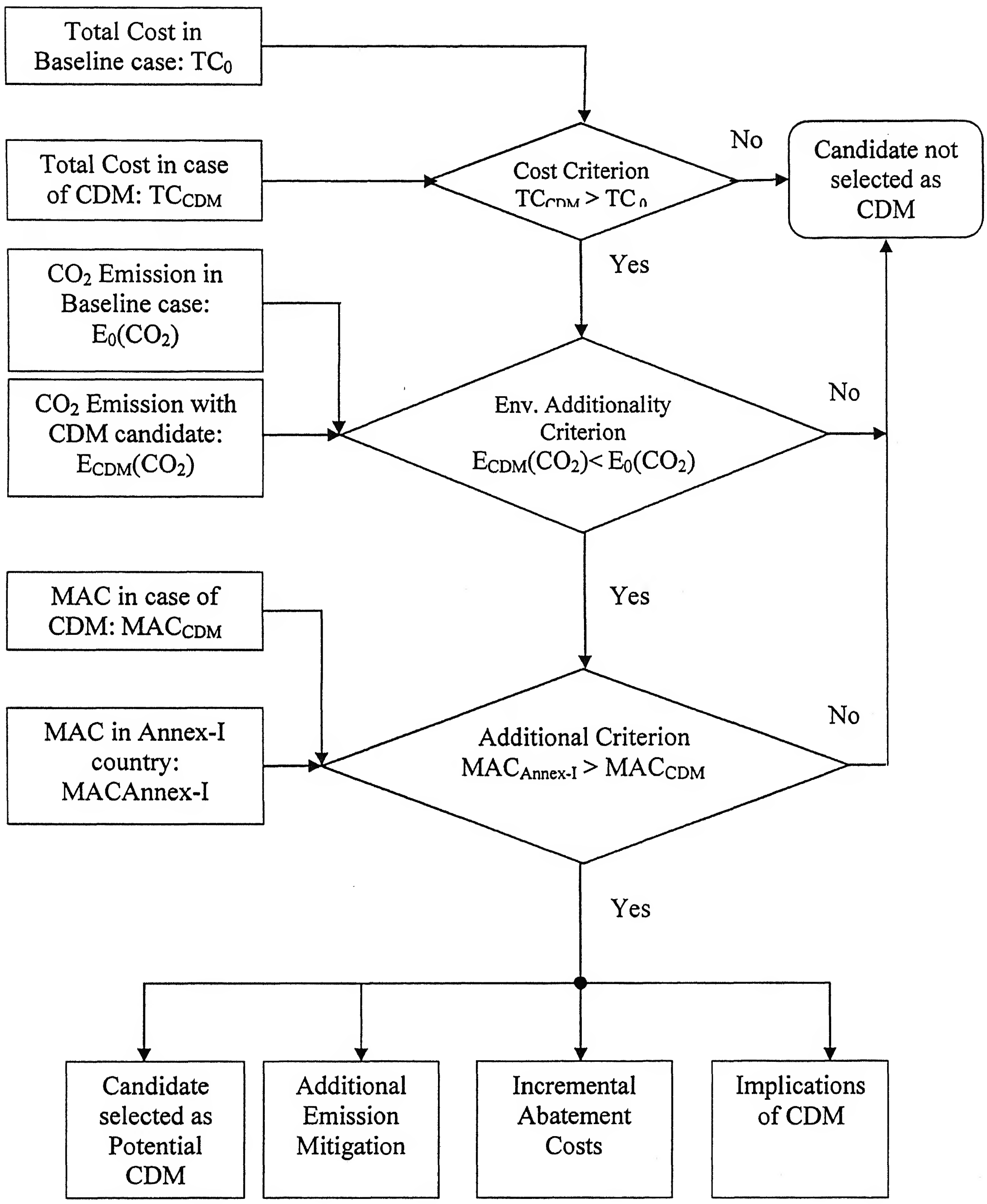

Figure 2.2: Selection of CDM Projects

2.4 Overview of Indian Power Sector

2.4.1 Electric power situation in the country

Power Development is the key to the economic development of any country. The power sector has been receiving adequate priority in India ever since the process of development began in 1950. Indian power sector has grown enormously over the past five decades. From an installed capacity of 1713 MW in 1950, it has grown to 112683.47 MW in the year 2004 [5]. In spite of such quantum increase in installed capacity, at present, the energy shortage is 7.1% and peak load shortage of 12.1% persisted during April to December 2004 [4]. As per the 16th Electric Power survey (EPS) of India [25] published by CEA, it is estimated that the country's peak demand would reach a figure of 157107MW and energy requirement of 975 billion units by the year 2011-12. To bridge the gap between demand and supply, there is an ambitious plan for power development to add another 100,000 MW of the installed capacity by the end of 2012.

The present power generation mix relies on domestic coal to provide three fifth of the country's power, large hydroelectric dams provide about one quarter. Gas fired power has grown from almost nothing to one tenth of the total generation in the last decade due to reduced risk associated with low capital requirements, shorter construction periods, reduced environmental impacts and higher efficiencies. Nuclear power contributes to less than three percent of the total generation. The installed capacity of different types of plants in the Indian power sector as on 31st March 2004 is shown in Table 2.1.

Table 2.1: Installed capacity in MW (As on 31.3.2004) [5]

Region	Hydro	Thermal	Diesel	Gas	Wind	Nuclear	Total
Northern	10588.39	15914.50	14.99	3213.20	178.50	1180.00	31089.58
Western	4986.58	20691.50	17.48	5035.72	632.46	760.00	32123.74
Southern	10363.07	13492.50	949.29	2650.40	1671.66	780.00	29906.92
Eastern	2455.77	14527.38	71.25	190.00	5.18	0.00	17429.58
North-Eastern	1113.02	330.00	119.82	750.50	0.32	0.00	2313.66
All India	**29506.83**	**64955.88**	**1172.83**	**11839.8**	**2488.12**	**2720.00**	**112683.5**

2.4.2 Electricity demand forecast

According to the 16th Electric Power Survey of India [25], the total peak load and Energy requirement projection of the country are given in Table 2.2 below:

Table 2.2: Peak load and energy requirement

Year	Energy requirement (MkWhr)	Peak Load (MW)	Load factor %
2006-07	719097	115705	70.95
2011-12	975222	157107	70.83
2016-17	1318644	212725	70.70

2.5 System Data and Assumptions

2.5.1 Existing plant data

The existing thermal and hydro power plant data has been taken from the 16th Electric Power Survey issued by the CEA [25]. After combining some of the identical units, it is found that there are total 760 existing thermal plants and 313 existing hydro plants. Detailed breakup of the existing thermal power plants is as shown in Table 3.3. The capacity of the plant, operating cost, fixed O&M costs, annual maintenance hours, plant availability, type of fuel used, fuel consumption rate, Calorific value of the fuel used, air pollutant emission rate, available hydro energy in the dry and wet seasons (in case of hydro power plants) and various other details are included in Appendix-A and B.

Table 2.3: Number of different types of thermal plants

Plant type	Coal	Gas	Oil	Lignite	Nuclear	**Total**
Number of plants	448	211	38	37	26	**760**

2.5.2 Electricity demand data

Electricity demand for the Indian system has been taken from 16th Electric Power Survey (EPS) of India [25], which projects the peak demand and energy up to year 2016. In the present study, demand forecast is required to be projected up to the year 2025. This forecast data is not available. So, peak demand up to 2025 has been extrapolated by taking average percentage growth of 6.3%. Demand in between the years has been calculated through interpolation of 16th EPS report data. Detailed forecast for each year of planning horizon is shown in Table 2.4.

Table 2.4: Electricity demand data-All India [25]

Year	Peak Demand MW	Load factor %	Energy Demand in (MkWh)
2006	115705	70.95	719097
2007	122982	70.94	764256
2008	130718	70.93	812251
2009	138940	70.93	863260
2010	147680	70.92	917473
2011	157107	70.83	974815
2012	166910	70.81	1035351
2013	177409	70.76	1099647
2014	188479	70.74	1167935
2015	200240	70.72	1240464
2016	212725	70.7	1317497
2017	226000	70.68	1399313
2018	240102	70.66	1486210
2019	255084	70.64	1578504
2020	271001	70.62	1676529
2021	287911	70.6	1780642
2022	305876	70.58	1891219
2023	324963	70.56	2008474
2024	345241	70.53	2132999
2025	366784	70.5	2265245

2.5.3 Candidate plant data

Six types of candidate thermal power plants have been considered viz., Coal 5-500MW, Coal-7 500 MW, CCGT 250MW, Lignite 250 MW, PFBC 500 MW and IGCC 500 MW.

Three types of candidate renewable power plants viz. wind, solar and BIGCC have been considered. The estimated technical potential of wind power available in the country is 13000 MW. India now has the 5th largest wind power installed capacity in the world, which has reached 1870 MW. Grid connected solar photovoltaic power projects aggregating to 2490 KW have so far been installed and other projects of capacity 800 KW are under installation. BIGCC combines gasification technology with the gas turbine technology to produce more output with cleaner emissions. BIGCC plants are expected to generate electricity at efficiencies exceeding 40% in the future and are currently at the early stages of commercialization. There exists a total potential of 16000MW of power using the BIGCC technology in the country [28].

No candidate nuclear power plant has been considered in this study. Candidate hydro power plants have been taken from the tentative list of hydro power plants expected to come after the year 2012. About 50 candidate hydro power plants have been considered in the study. Details of these plants are given in Appendix-C.

2.5.4 Supply side options

a) Clean coal technologies

Two types of clean coal technologies viz. Pressurized Fluidized Bed Combustion (PFBC) and Integrated Gasification Combined Cycle (IGCC) are considered as supply side options in the present study [34].

b) Renewable technologies

In the present study, Wind, BIGCC and Solar are considered as renewable technologies. Solar plants of capacity 2 MW, BIGCC plants of capacity 132 MW and wind

plants of capacity 10 MW are considered. Daily energy generation pattern of Wind and Solar plants has been obtained by using wind speed and solar radiation data of some specific locations in India [34,35]. Detailed data of these plants is given in Appendix-C.

2.5.5 Demand side options

End use efficiency improvement and Demand Side Management (DSM), offer new hope to Indian utilities to bring the demand and supply of electricity closer into balance, when the country is experiencing an overall energy deficiency with peak demand remaining unserved. Five categories of demand side options have been considered for the present study, three in the residential sector and two in the agricultural sector. These are listed as following:

Table 2.5: DSM options considered for the study

Sector	DSM Options
Residential	DSM 1: Replacement of 100W incandescent bulb by 20W CFL DSM 2: Replacement of 60W incandescent bulb by 11W CFL DSM 3: Replacement of 40W incandescent bulb by 9W CFL
Agricultural	DSM 4: Replacement of inefficient pumps by efficient ones DSM 5: Partial rectification of pumps

In 2003-04, the total connected domestic load was approximately 49% of the total connected load. Lighting accounts for 28% share of the total domestic energy consumption. Present lighting system used in the domestic sector is largely incandescent lamps and to some extent fluorescent lamps. In the domestic sector, there exists a very strong case for substituting low efficiency incandescent lamps with high efficiency fluorescent lamps, while increasing the level of lumen output [29,30]. Chronological load curve of the residential sector is based on survey report done for Gujarat State Electricity Board [30].

India is primarily an agriculture based country. Agriculture pumps account for 23% of electricity consumption [32]. Thus, rectification of agriculture pumps is a promising DSM option. Complete rectification of the agriculture pumps involves changing of inefficient pumps with efficient ones, which increases the efficiency up to 65%. Partial rectification of agriculture pumps includes replacement of local foot valve by low resistance foot valve, substitution of G.I. pipe in suction line by low friction RPVC pipe of proper diameter, which increases the efficiency by 27% [32]. Chronological load curve for the agriculture sector is taken from a TERI report based on study done in Uttar Pradesh. The detailed data for DSM is shown in Appendix-C.

2.5.6 Assumptions

In the present study, most of the data are consistent with the norms used in India for power generation expansion planning. The assumptions made in this study are listed below:

1. The planning horizon is taken as 2006-2025, base year is considered as 2000 and discount rate as 10%. Reserve margin is taken as 5% for all the years. Transmission loss rate is taken as 4%.
2. For hydro plants, twenty blocks are taken in one season and two seasons are considered in one year. Season 1 is of total 92 days (July, August and September) and seasons 2 (rest of the months) consist of total 273 days. All the cost figures are taken for the base year of 2000.
3. Minimum operating capacity is taken as 30% of the installed capacity for thermal power plants. Operating cost is taken as 1% of the total capital cost and fixed operating and maintenance (O&M) cost as 2.5% for thermal plants. Operating cost for hydro plants is assumed to be zero and fixed O&M cost is taken as 1.5% of the total capital cost. Annual maintenance hours are taken as 864 for coal and Nuclear based power plants, 1296 for gas and oil based power plants. Availability of existing power plants is shown in Table 2.4. The Availability factor for candidate

thermal plants like Coal 5 and Coal7 has been taken as 0.73. For hydro plants it is 0.87, for IGCC and PFBC it is taken as 0.85, for gas-based plants it is taken as 0.71. These figures are based on the norms used by CEA.

Table 2.6 Availability factor for existing power plants

Plant based on	Coal	Nuclear	Gas	Lignite	Hydro	Oil	IGCC&PFBC
Availability Factor	0.73	0.58	0.71	0.71	0.87	0.8	0.85

4. Life time of the power plants has been considered as 30 years. It is also assumed that no existing power plant would retire during the planning horizon as the stations are undertaking many schemes for renovation and modernization regularly.
5. Nineteen types of fuels have been considered which include 12 types of coal with different GCV and prices, Gas, Lignite, Nuclear, Oil, Biomass, Solar and Wind.
6. It is assumed that the data of fuel consumption, GCV of Fuel and heat rate furnished by the stations are correct.
7. The GCV of the fuel for each station has been assumed to be within the range of the GCV of fuel types considered.
8. Committed power plant data has been taken from the perspective plan of capacity addition issued by Government of India [26].
9. In DSM data, replacement of incandescent bulbs by Compact Fluorescent Lamps (CFL) are derived from the available references [29,30,32]. Breakdown of GLS lamps of different power ratings i.e., 40, 60, 100 Watts and others in the residential sector are assumed in the ratio of 45:35:15:5. Breakdown of installed GLS lamps in different sectors i.e., domestic, commercial and industrial are assumed in the ratio of 70:25:5. This ratio is just an intelligent assumption based on survey report done in small region of Gujarat [31].
10. For easiness of study and sensitivity analysis, all units of plausible CDM plants have been committed simultaneously in one year assuming that all amount needed for installation is available from one of the Annex-I countries.

2.6 Analysis of Results

The detailed results of the study are presented in Chapter-3. The analysis has been carried out to study the following aspects:

2.6.1 Utility planning implications

For different cases considered, the generation capacity mix, generation technology mix, fuel mix, DSM programs selected, etc., have been compared under different scenarios.

2.6.2 Economical/Financial implications

For different cases considered, the expenditures related to electricity generation costs, capacity costs, DSM costs, and annual investment requirements during the planning horizon would be discussed. Electricity price could be expressed as the sum of the average incremental cost (AIC) of generation and long run marginal cost (LRMC) of the transmission and distribution.

Electricity price = Total LRMC = AIC + $LRMC_T$ + $LRMC_D$

Shrestha et al. [21] estimated AIC at the generation level by using the following formula:

$$\text{AIC} = \left(TC - C_1 - \sum_{i=1}^{T} VC_1 / (1+r)^i \right) \Big/ \left(\sum (E_i - E_1) / (1+r^i) \right)$$

Where TC = Present value of total cost.

C_1 = Present value of capital cost in year 1.

VC_1 = Total fuel, O&M, and DSM costs(in case of IRP) in year 1.

E_1, E_i = Electricity generation in year 1 and i respectively.

r = Discount rate

T = Planning horizon.

2.6.3 Environmental implications

To assess the role of CDM options under both TRP and IRP, the expansion planning model has been run by committing the candidate power plants and also for base case without these plants. The difference in air pollutant emission under these cases gives the contribution of these plants in mitigating emissions. The mitigation costs due to these plants are also calculated. The average marginal abatement cost (MAC) of a environmental pollutant can be calculated as follows (Maya and Fenhann [24]):

$$\mathrm{MAC} = \left(TC_c - TC_0\right) / \left\{ \sum_{t=1}^{T} \left(E_{0,t} - E_{c,t}\right) / (1+r)^t \right\}$$

Where TC_C = Present value of total cost in the case where candidate CDMs are committed.

TC_0 = Present value of total cost in case where candidate CDMs are not committed.

$E_{0,t}$ = Pollutant emission in year t in case where candidate CDMs are not committed.

$E_{c,t}$ = Pollutant emission in year t in case where candidate CDMs are committed.

r = Discount rate

T = Number of years in the planning horizon.

2.7 Conclusions

The methodology for identifying projects under the Clean Development Mechanism (CDM) using least cost generation expansion planning studies has been presented in this chapter. An overview of the present Indian power system has also been included. The input data, various supply side and demand side options considered in the study were described. The methodology for analyzing the impact of Clean Development Mechanism options on utilities, electricity price, expansion costs and GHG emissions has also been presented.

Chapter 3

System Studies

3.1 Introduction

The previous chapter has presented the methodology for identification of the Clean Development Mechanism (CDM) projects based on the least cost generation expansion planning studies and also the details of the Indian power sector data to be utilized in this study. This chapter presents the results of the generation expansion planning studies carried out on the Indian power sector data under Traditional Resource Planning (TRP) scenario, i.e. without considering any Demand Side Management (DSM) options, and also under the Integrated Resource Planning (IRP) scenario, i.e. considering both the supply side and demand side management options. Plausible CDM options in the power sector are those plants, which do not get selected in the normal least cost generation expansion planning exercise due to their high cost but has potential to reduce the GHG emissions (only CO_2 emissions considered in this study), when such plants are intentionally committed in the planning studies. Trading under CDM can take place with those countries (or a country), where the Marginal Abatement Cost (MAC) to reduce the GHG emissions is higher than the Marginal Abatement Cost found with the plausible CDM options.

In India, the generation expansion planning is normally carried out by the Central Electricity Authority (CEA), New Delhi, separately for each of the five regions. However, as the country is moving ahead with strong national grid and to utilize the diverse resources available in each region, it is worth considering the integrated planning at the national level. Hence, TRP and IRP studies in the present work have been carried out for the integrated Indian power system network.

3.2 CDM Options Identified for TRP and IRP Baselines

The least cost generation planning exercise was carried out for the integrated Indian power system data as described in previous chapter and Appendix A, B and C for the TRP base case and the IRP base case. The details of the technology options (Thermal, Nuclear, Renewables and Hydro), that were selected in these cases during the planning horizon of 2006-2025, are given in Tables 3.1, 3.2, 3.3 and 3.4.

Table 3.1: Technology options (Thermal & Renewables) selected in TRP base case

Year	Coal-5 (500)	Coal-7 (500)	CCGT (250)	PFBC (500)	IGCC (400)	Lignite (250)	Solar (2)	Wind (10)	BIGCC (132)
2006	27	0	20	1	1	4	0	500	0
2007	27	0	20	1	1	4	0	500	0
2008	27	0	20	1	1	5	0	500	0
2009	27	0	25	1	1	5	0	500	0
2010	27	0	30	1	1	18	0	500	0
2011	27	0	35	1	1	22	0	500	0
2012	27	0	40	1	1	28	0	500	0
2013	27	0	45	3	1	32	0	1000	0
2014	27	0	50	15	8	36	0	1000	0
2015	27	0	55	17	17	40	0	1000	0
2016	32	0	60	19	19	44	0	1000	0
2017	61	0	65	21	21	48	0	1000	0
2018	90	0	70	22	22	52	0	1000	0
2019	125	0	75	23	23	56	0	1000	0
2020	162	0	80	25	25	60	0	1000	0
2021	203	0	85	26	26	64	0	1000	0
2022	230	0	90	27	27	68	0	1000	0
2023	250	20	95	28	28	72	0	1000	0
2024	250	69	105	29	29	76	0	1000	0
2025	275	93	115	30	30	80	0	1000	0

Table 3.2: Technology options (Hydro) selected in TRP base case

Plant selected	No. of units selected	Size of each unit (MW)	Year in which the plant is selected
Dhauliganga II	3	70	2013
Kishanganga	3	110	2013
Kotlibhel	4	250	2013
Uri II	9	70	2013
Bajoli Holi	2	100	2013
Jhangi Thopan	1	410	2013
Bhawani Kattalai	1	90	2013
Pandiar Punnapuzha	1	100	2013
Teesta St-II	8	100	2013
Barak	1	90	2013
Kirthai I	2	120	2013
Khab-II	4	105	2013
Nukcharoong	1	60	2013
Uttaranchal Combined	12	40	2013
Sisiri	2	110	2014
Mananthwadi	2	120	2015
Upper Siang I	10	250	2015
Upper Siang 2	2	250	2015
Upper Siang 3	10	250	2015
Upper Siang 5	4	250	2015
Binoda	6	100	2016
Lohit	6	500	2016
Kirthai II	3	120	2016
Kerala Bhawani	1	150	2016
Upper Siang 2	8	250	2016
Upper Siang 4	10	250	2016
Lower Siang St 1	4	100	2018
Lower Siang St 2	4	100	2018
Lower Siang St 3	4	100	2018
Lower Siang St 4	4	100	2018
Dummugudam	4	90	2019
Gundia High Head	2	120	2019
Luhri	1	425	2022
Bedthi	4	105	2022
Dibang St 1	6	250	2022
Dibang St 2	6	250	2022
Dibang St 3	6	250	2022
Dibang St 4	6	250	2022
Maharashtra Combined	1	65	2022
Maslej Ghat	6	100	2023

Varandh Ghat	10	100	2023
Humbarli	4	100	2023
Middle Siang	4	250	2023
Sone	1	100	2023
Lower Jurala	1	160	2023
Maharashtra Combined	3	65	2023
Mangot Combined St 1	1	150	2024
Kadwan	5	90	2025
Kanhar	3	100	2025
Hirakud-B	4	102	2025
Singareddy	2	100	2025
Sankh II	1	186	2025

Table 3.3: Technology options (Thermal & Renewables) selected in IRP base case

Year	Coal-5 (500)	Coal-7 (500)	CCGT (250)	PFBC (500)	IGCC (400)	Lignite (250)	Solar (2)	Wind (10)	BIGCC (132)
2006	0	0	20	0	0	4	0	500	0
2007	0	0	20	0	0	4	0	500	0
2008	0	0	20	0	0	4	0	500	0
2009	0	0	25	0	0	4	0	500	0
2010	0	0	30	0	0	4	0	500	0
2011	0	0	35	0	0	4	0	500	0
2012	0	0	40	0	0	4	0	500	0
2013	0	0	45	0	0	4	0	1000	0
2014	0	0	50	0	0	4	0	1000	0
2015	0	0	55	0	0	4	0	1000	0
2016	0	0	60	0	0	4	0	1000	0
2017	0	0	65	0	0	4	0	1000	0
2018	0	0	70	0	0	4	0	1000	0
2019	0	0	75	0	0	29	0	1000	0
2020	0	0	80	1	0	60	0	1000	0
2021	0	0	85	24	0	64	0	1000	0
2022	0	0	90	27	23	68	0	1000	0
2023	25	0	95	28	28	72	0	1000	0
2024	54	0	105	29	29	76	0	1000	0
2025	89	0	115	30	30	80	0	1000	0

Table 3.4: Technology options (Hydro) selected in IRP base case

Plant selected	No. of units selected	Size of each unit (MW)	Year in which the plant is selected
Kotlibhel	4	250	2015
Uttaranchal Combined	12	40	2015
Dhauliganga II	3	70	2016
Kishanganga	3	110	2016
Uri II	9	70	2016
Bajoli Holi	2	100	2016
Jhangi Thopan	1	410	2016
Bhawani Kattalai	1	90	2016
Pandiar Punnapuzha	1	100	2016
Teesta St- II	8	100	2016
Barak	1	90	2016
Kirthai I	2	120	2016
Mananthwadi	2	120	2017
Sisiri	2	110	2017
Khab-II	4	105	2017
Nukucharoong	1	60	2017
Upper Siang 1	2	250	2017
Upper Siang 2	10	250	2017
Upper Siang 3	10	250	2017
Upper Siang 4	10	250	2017
Upper Siang 5	4	250	2017
Binoda	6	100	2018
Dummugudum	4	90	2018
Gundia High Head	2	120	2018
Lohit	6	500	2018
Kirthai-II	2	120	2018
Kerala Bhawani	1	150	2018
Lower Siang St 1	4	100	2018
Lower Siang St 2	4	100	2018
Lower Siang St 3	4	100	2018
Lower Siang St 4	4	100	2018
Dibang St 2	6	250	2018
Upper Siang 1	8	250	2018
Luhri	1	425	2019
Bedthi	4	105	2019
Sone	1	100	2019
Dibang St 1	6	250	2019
Dibang St 3	6	250	2019
Dibang St 4	6	250	2019
Maharashtra Combined	4	65	2019

Maslej Ghat	6	100	2020
Varand Ghat	10	100	2020
Humbarli	4	100	2020
Kadwan	5	90	2020
Kanhar	3	100	2020
Middle Siang	4	250	2020
Mangot Combined St 1	1	150	2020
Singareddy	2	100	2020
Lower Jurala	1	160	2020
Sankh- II	1	186	2020
Hirakud-B	4	102	2021

Tables 3.2 and 3.4 indicate that all the candidate hydro plants got selected in both the TRP and IRP base cases. The plants, which are not at all selected in the base case during the planning horizon for the TRP as well as the IRP base case, are Solar and BIGCC technologies. These plants which are not selected in the base case during the planning horizon are considered as plausible CDM options for further analysis. Thus, plausible CDM options identified at IRP and TRP baseline are:

TRP baseline:

1) Solar (500 units of 2 MW each and earliest available year is 2006)
2) BIGCC (50 units of 132 MW each and earliest available year is 2006).

IRP baseline:

1) Solar (500 units of 2 MW each and earliest available year is 2006)
2) BIGCC (50 units of 132 MW each and earliest available year is 2006).

These identified plausible CDM options were forced to be selected in the generation expansion planning studies by considering these plants as committed plants in the year of their earliest availability.

3.3 Implications of CDM on Generation mix and Capacity mix:

The implications of different types of CDM options on the generation and capacity mix were studied by committing the respective plants in their earliest available year. The following four cases were considered to study the impact of the CDM options:

Case-1: TRP with Solar as CDM option

Case-2: TRP with BIGCC as CDM option

Case-3: IRP with Solar as CDM option

Case-4: IRP with BIGCC as CDM option.

Table 3.5 Generation mix by plant types for TRP baseline (%)

Generation Planning Case		Generation mix (%)											Total (GWh)
		Hydro	Coal	CCGT	Nuclear	Lignite	Oil	PFBC	IGCC	Wind	Solar	BIGCC	
Base Case	2006	16.2	60.9	12.9	2.2	3.4	0.9	0.4	0.4	2.7	0	0	790532.0
	2010	17.4	62.7	7.8	2.8	5.9	0.7	0.3	0.3	2.1	0	0	1009243.3
	2014	17.6	51.8	11.7	2.4	6.6	0.6	3.9	2.1	3.3	0	0	1287412.9
	2018	17.1	51.8	10.6	1.8	6.6	0.5	4.5	4.5	2.6	0	0	1640517.9
	2022	14.2	59.9	7.2	1.5	6.2	0.4	4.3	4.3	2.0	0	0	2090416.7
	2025	12.2	65.1	5.6	1.2	5.9	0.3	4.0	4.0	1.7	0	0	2507031.7
Solar as CDM	2006	16.2	60.8	12.9	2.2	3.4	0.9	0.4	0.4	2.7	0	0	790521.2
	2010	17.4	62.8	7.6	2.8	4.2	0.7	0.3	0.3	2.1	0.1	0	1009212.9
	2014	17.6	51.8	11.6	2.4	6.6	0.6	3.9	2.1	3.3	0.1	0	1287365.4
	2018	17.1	51.8	10.6	1.9	6.6	0.5	4.5	4.5	2.6	0.1	0	1640453.1
	2022	14.2	60.0	6.9	1.5	6.2	0.4	4.3	4.3	2.0	0.1	0	2090330.1
	2025	12.2	65.0	5.6	1.2	5.9	0.3	4.0	4.0	1.7	0.1	0	2506923.5
BIGCC as CDM	2006	16.2	60.1	12.7	2.2	3.4	0.9	0.4	0.4	2.7	0	0.9	790532.0
	2010	17.4	62.0	7.6	2.8	6.1	0.7	0.3	0.3	2.1	0	0.6	1009243.3
	2014	17.6	51.3	11.3	2.4	6.6	0.6	3.9	2.1	3.3	0	0.9	1287412.9
	2018	17.1	49.8	10.6	1.9	6.6	0.5	4.5	4.5	2.6	0	2.0	1640517.9
	2022	13.5	60.0	6.8	1.5	6.2	0.4	4.3	4.3	2.0	0	0.9	2090416.7
	2025	12.1	64.4	5.6	1.2	5.9	0.3	4.0	4.0	1.7	0	0.8	2507031.7

The results in Table 3.5, which shows the generation mix of plants under the TRP baseline, indicate the following:

Case-1: Solar as CDM option (TRP)

1) The generations from CCGT and Lignite plants have decreased slightly, when compared to their generation in the TRP base case.
2) The generations from Coal, Nuclear, PFBC, IGCC, Wind, Hydro and Oil plants are not affected.
3) The generation from Solar plants has increased.

Case-2: BIGCC as CDM option (IRP)

1) The generation from Coal plants has decreased considerably while the generations from Hydro, Lignite and CCGT plants have decreased slightly, when compared to their respective generations in the TRP base case.
2) The generations from Nuclear, PFBC, IGCC, Solar, Wind and Oil plants are not affected.
3) The generation from BIGCC plants has increased.

Table 3.6: Generation mix by plant types for IRP baseline (%)

Generation Planning Case		Generation mix (%)											Total (GWh)
		Hydro	Coal	CCGT	Nuclear	Lignite	Oil	PFBC	IGCC	Wind	Solar	BIGCC	
Base Case	2006	17.9	57.7	15.7	2.4	3.8	2.1	0	0	0.4	0	0	715198.1
	2010	23.7	55.4	10.2	3.8	5.5	1.0	0	0	0.4	0	0	738971.6
	2014	24.4	55.0	10.8	3.7	4.8	0.9	0	0	0.4	0	0	831556.4
	2018	28.6	52.5	10.6	3.1	4.1	0.8	0	0	0.3	0	0	994186.7
	2022	25.4	36.4	9.9	2.5	10.8	0.6	7.5	6.4	0.3	0	0	1202127.0
	2025	21.7	41.3	9.6	2.2	10.4	0.5	7.0	7.1	0.2	0	0	1411654.0
Solar as CDM	2006	17.9	57.7	15.7	2.4	3.8	2.1	0	0	0.4	0	0	715198.0
	2010	23.7	55.4	10.2	3.8	5.5	1.0	0	0	0.4	0.1	0	738951.9
	2014	24.4	54.9	10.8	3.7	4.8	0.9	0	0	0.4	0.1	0	831519.3
	2018	28.6	52.4	10.6	3.1	4.1	0.8	0	0	0.3	0.2	0	994132.4
	2022	25.4	36.5	10.0	2.5	10.8	0.6	7.5	6.1	0.3	0.2	0	1201673.0
	2025	21.7	41.2	9.6	2.2	10.4	0.5	6.9	7.1	0.2	0.2	0	1411058.2
BIGCC as CDM	2006	17.9	57.7	15.7	2.4	3.0	2.1	0	0	0.2	0	1.0	715257.4
	2010	23.7	55.6	10.2	3.8	4.7	1.0	0	0	0.2	0	0.9	740071.1
	2014	24.3	54.7	10.8	3.7	4.2	0.9	0	0	0.2	0	1.3	833883.4
	2018	27.5	52.7	10.9	3.1	3.5	0.8	0	0	0.2	0	1.4	997523.1
	2022	25.4	38.3	10.4	2.5	10.8	0.6	7.5	2.8	0.1	0	1.4	1202487.7
	2025	21.7	39.9	9.7	2.2	10.4	0.5	7.1	7.1	0.1	0	1.3	1410962.1

The results in Table 3.6, which shows the generation mix of plants under the IRP baseline, indicate the following:

Case-3: Solar as CDM option (IRP)

1) The generation from CCGT plants has increased slightly, when compared to their generation in the IRP base case.
2) The generations from Coal, PFBC and IGCC plants have increased slightly, when compared to their generation in the IRP base case. The generations from Hydro, Nuclear, Oil, Lignite, BIGCC and Wind plants are not affected.
3) The generation from Solar plants has increased.

Case-4: BIGCC as CDM option (IRP)

1) The generations from Lignite, IGCC and Wind plants have decreased considerably. The generations from Hydro and Coal plants have decreased slightly, when compared to their respective generations in the IRP base case.
2) The generations from Nuclear, PFBC, Solar, and Oil plants are not affected.
3) The generation from BIGCC plants has increased.

The results in Table 3.7, which shows the capacity mix of plants in the TRP baseline, indicate the following:

Case-1: Solar as CDM option (TRP)

1) The capacities of Hydro, Coal and IGCC plants have decreased slightly, when compared to their respective capacities in the TRP base case.
2) The capacities of CCGT, Nuclear, Lignite, Oil, PFBC, Wind and BIGCC plants are not affected.
3) The capacity of Solar plants has increased.

Case-2: BIGCC as CDM option (TRP)

1) The capacities of Coal and CCGT plants have decreased slightly and the capacities of Hydro and Lignite plants have changed slightly, when compared to their respective capacities in the TRP base case.
2) The capacities of Nuclear, Oil, PFBC, IGCC, Wind, and Solar plants are not affected.
3) The capacity of BIGCC plants has increased.

Table 3.7: Capacity mix by plant types for TRP baseline (%)

Generation Planning Case		Capacity mix (%)											Total (MW)
		Hydro	Coal	CCGT	Nuclear	Lignite	Oil	PFBC	IGCC	Wind	Solar	BIGCC	
Base Case	2006	23.6	53.0	12.8	2.3	2.9	1.6	0.3	0.3	3.0	0	0	164667.5
	2010	23.8	51.8	12.9	2.8	4.8	1.3	0.2	0.2	2.2	0	0	222594.5
	2014	24.8	45.2	12.8	2.5	5.7	1.0	2.8	3.0	3.7	0	0	267118.5
	2018	24.8	45.4	11.7	2.0	5.7	0.8	3.3	3.2	3.0	0	0	335068.5
	2022	21.2	52.1	10.3	1.6	5.4	0.7	3.2	3.1	2.3	0	0	426578.5
	2025	18.7	56.8	9.8	1.3	5.1	0.5	2.9	2.9	1.9	0	0	512977.5
Solar as CDM	2006	23.6	53.0	12.8	2.3	2.9	1.6	0.3	0.3	3.0	0.1	0	164767.5
	2010	23.7	51.8	12.9	2.8	4.7	1.3	0.2	0.2	2.2	0.1	0	222624.5
	2014	24.7	45.1	12.8	2.5	5.7	1.0	2.8	1.5	3.7	0.2	0	267558.5
	2018	24.8	45.3	11.7	2.0	5.7	0.8	3.3	3.3	3.0	0.2	0	335668.5
	2022	21.2	52.0	10.3	1.6	5.4	0.7	3.2	3.2	2.3	0.2	0	427878.5
	2025	18.6	56.6	9.8	1.3	5.1	0.5	2.9	2.9	1.9	0.2	0	513477.5
BIGCC as CDM	2006	23.6	52.4	12.8	2.3	2.9	1.6	0.3	0.3	3.0	0	0.6	164723.5
	2010	23.6	51.0	12.8	2.8	4.9	1.3	0.2	0.2	2.2	0	1.1	224220.5
	2014	24.5	44.3	12.6	2.5	5.6	1.0	2.8	1.5	3.7	0	1.5	270078.5
	2018	24.8	43.8	11.7	2.0	5.7	0.8	3.3	3.3	3.0	0	1.6	334848.5
	2020	22.0	48.1	11.0	1.8	5.6	0.7	3.3	3.3	2.6	0	1.5	378376.5
	2025	18.4	55.7	9.8	1.3	5.1	0.5	2.9	2.9	2.0	0	1.3	512533.5

The results in Table 3.8, which shows the capacity mix of plants under the IRP baseline, indicate the following:

Case-3: Solar as CDM option (IRP)

1) The capacity of Coal plants has decreased slightly, when compared to their capacity in the IRP base case, whereas the capacities of Hydro, IGCC and Wind plants have changed slightly, when compared to their capacities in the IRP base case.
2) The capacities of Nuclear, CCGT, Oil, PFBC and BIGCC plants are not affected.
3) The capacity of Solar plants has increased.

Table 3.8: Capacity mix by plant types for IRP baseline (%)

Generation Planning Case		Hydro	Coal	CCGT	Nuclear	Lignite	Oil	PFBC	IGCC	Wind	Solar	BIGCC	Total (MW)
		Capacity mix (%)											
Base Case	2006	26.6	50.6	14.5	2.6	3.3	1.8	0	0	0.5	0	0	145907.5
	2010	26.4	50.9	14.3	3.1	3.6	1.4	0	0	0.4	0	0	200334.5
	2014	27.7	48.8	15.5	3.1	3.3	1.3	0	0	0.3	0	0	219578.5
	2018	34.2	43.0	15.7	2.7	2.9	1.1	0	0	0.3	0	0	248908.5
	2022	31.3	35.1	14.4	2.2	7.6	0.9	4.4	3.8	0.2	0	0	305467.5
	2025	26.3	41.6	13.8	1.8	7.2	0.8	4.1	4.1	0.2	0	0	364217.5
Solar as CDM	2006	26.6	50.6	14.5	2.6	3.3	1.8	0	0	0.5	0.1	0	145947.5
	2010	26.4	50.8	14.3	3.1	3.8	1.4	0	0	0.3	0.1	0	200554.5
	2014	27.7	48.7	15.5	3.1	3.3	1.3	0	0	0.3	0.2	0	219959.0
	2018	34.1	43.0	15.7	2.7	2.9	1.1	0	0	0.3	0.2	0	249198.5
	2022	31.3	35.0	14.4	2.2	7.6	0.9	4.4	3.6	0.2	0.3	0	305707.5
	2025	26.3	41.4	13.8	1.8	7.2	0.8	4.1	4.1	0.2	0.3	0	364657.5
BIGCC as CDM	2006	26.7	50.7	14.5	2.6	2.6	1.8	0	0	0.3	0	0.7	145633.5
	2010	26.3	50.6	14.2	3.1	3.1	1.4	0	0	0.2	0	1.2	2013805
	2014	27.4	48.2	15.4	3.0	2.8	1.3	0	0	0.2	0	1.8	222208.5
	2018	32.7	43.0	15.7	2.7	2.5	1.1	0	0	0.2	0	2.1	249008.5
	2022	31.3	35.2	14.4	2.2	7.6	0.9	4.4	1.6	0.1	0	2.1	305473.5
	2025	26.4	39.7	13.9	1.8	7.2	0.8	4.1	4.1	0.1	0	1.8	362987.5

Case-4: BIGCC as CDM option (IRP)

1) The capacities of Lignite, IGCC and Wind plants have decreased, when compared to their respective capacities in the IRP base case. The capacities of Hydro, Coal and CCGT plants have changed slightly, when compared to their respective capacities in the IRP base case.
2) The capacities of PFBC, Oil and Solar plants are not affected.
3) The capacity of BIGCC plants has increased.

3.4 Environmental Implications of CDM Options

3.4.1 Total emissions and emissions avoided for TRP baseline

Table 3.9 presents the values of different types of emissions i.e., CO_2, SO_2 and NO_X for each type of CDM options for the TRP baseline. The amount of reduction of different types of emissions is given in Table 3.10, while comparing these with the respective base case values for the TRP base case.

Tables 3.9 and 3.10 indicate that both Solar and BIGCC, considered as CDM options in the TRP baseline, result in a reduction of total emissions of CO_2, SO_2 and NO_X. It is also evident from these tables that the BIGCC plants are more effective in avoiding CO_2, SO_2 and NO_X emissions, as compared to the solar plants considered in the study.

Table 3.9: Total emissions for TRP baseline

Case	Total emissions		
	CO_2 (Gkg)	**SO_2 (Mkg)**	**NO_X (Mkg)**
Base case	23420.6	112189.9	56009.8
Solar as CDM	23401.1	112075.8	55962.8
BIGCC as CDM	23120.6	110539.3	55425.1

Table 3.10: Emissions avoided for TRP baseline

Case	Emissions Avoided		
	CO_2 (Gkg)	**SO_2 (Mkg)**	**NO_X (Mkg)**
Solar as CDM	19.5	114.1	47.0
BIGCC as CDM	300.0	1650.6	585.7

3.4.2 Total emissions and emissions avoided for IRP baseline

Table 3.11 presents the values of different types of emissions i.e., CO_2, SO_2 and NO_X for each type of CDM options for the IRP baseline. The amount of reduction of different types of emissions is given in Table 3.12, while comparing these with the respective base case values for the TRP base case.

Tables 3.11 and 3.12 indicate that Solar considered as CDM options result in a reduction of total emissions of CO_2, SO_2, and NO_X. Considering BIGCC as CDM has the effect of decreasing total emissions of CO_2 and SO_2, while the emissions of NO_X have increased.

Thus, it evident that BIGCC plants are more effective in avoiding CO_2 and SO_2 emissions, while Solar plants are more effective in avoiding NO_X emissions.

Table 3.11: Total emissions for IRP baselines

Case	Total Emissions		
	CO_2 (Gkg)	SO_2 (Mkg)	NO_X (Mkg)
Base case	13525.9	62233.2	32922.5
Solar as CDM	13505.2	62120.6	32878.6
BIGCC as CDM	13403.1	60759.2	32950.4

Table 3.12: Emissions avoided for IRP baselines

Case	Emissions avoided		
	CO_2 (Gkg)	SO_2 (Mkg)	NO_X (Mkg)
Solar as CDM	20.7	112.6	43.9
BIGCC as CDM	122.8	1474.0	-27.9

3.5 Cost Implications of CDM options

Table 3.13 and 3.14 show the implication of CDM options on various generation expansion costs during the planning horizon for the TRP and IRP baselines, respectively. It can be observed that the total cost increases in all the cases, when CDM plants are committed. Thus, both Solar and BIGCC qualify as CDM projects as they satisfy the additionality cost criterion. Cost figures are also shown in Fig 3.1.

Table 3.13: Expansion costs during planning horizon for TRP baseline

Cost in M$	Base case	Solar as CDM	BIGCC as CDM
Capital Cost (1)	40994.9	42344.2	41601.7
Fixed O&M Cost (2)	30633.8	30680.2	31411.9
Fuel & Variable Cost (3)	128308.4	128189.1	129566.9
Fuel and O&M Cost (2+3)	158942.2	158869.3	160978.8
Sub Total (1+2+3)	199937.1	201213.5	202580.5
DSM Cost (4)	0	0	0
Total Cost (1+2+3+4)	199937.1	201213.5	202580.5
MAC ($/ton of Carbon)	NA	194.41	28.24

Table 3.14: Expansion costs during planning horizon for IRP baseline

Cost (M$)	Base case	Solar as CDM	BIGCC as CDM
Capital Cost (1)	14139.4	15452.8	14598.7
Fixed O&M Cost (2)	24932.9	24975.3	25687.1
Fuel & Variable Cost (3)	91309.6	91247.8	93013.1
Fuel and O&M Cost (2+3)	116242.5	116223.1	118700.2
Sub Total (1+2+3)	130381.9	131675.9	133298.9
DSM Cost (4)	1419.6	1419.7	1415.0
Total Cost (1+2+3+4)	131801.5	133095.6	134713.9
MAC ($/ton of Carbon)	NA	220.22	70.26

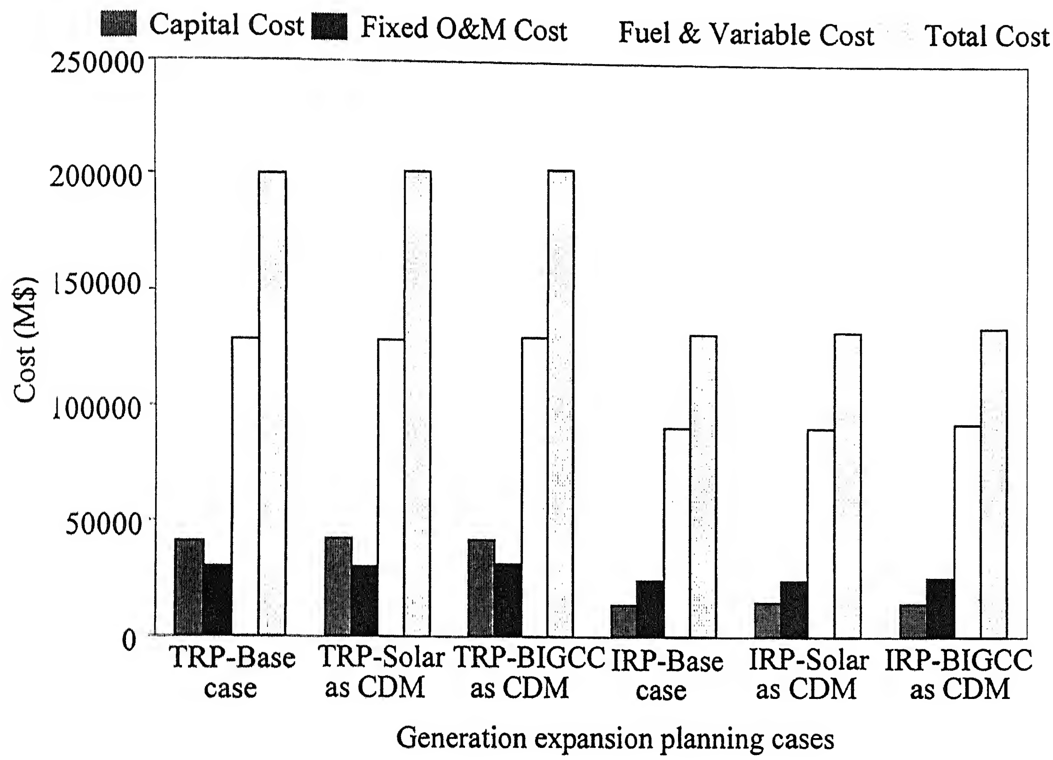

Fig 3.1: Expansion costs during planning horizon

Table 3.15 shows the impact of CDM options on Average Incremental Cost (AIC), which is an index of electricity prices. In both the TRP and IRP baselines, AIC is maximum, when BIGCC is considered as a CDM option.

Table 3.15: Electricity prices for expansion planning cases

Electricity price (US cents/kWh)	Generation expansion planning cases					
	TRP Base case	TRP Solar as CDM	TRP BIGCC as CDM	IRP Base case	IRP Solar as CDM	IRP BIGCC as CDM
Without including DSM cost	2.53	2.57	2.60	0.64	0.78	0.87
With DSM cost included	-	-	-	0.77	0.90	1.00

3.6 Sensitivity Analyses

Sensitivity analyses were carried out to observe the impact of changing the commitment year of CDM options on the emissions of pollutants and also on Total Cost and Marginal Abatement Cost. The results of sensitivity analyses are given below.

3.6.1 Sensitivity of TC and MAC to year of commitment of the CDM options

a) For TRP case

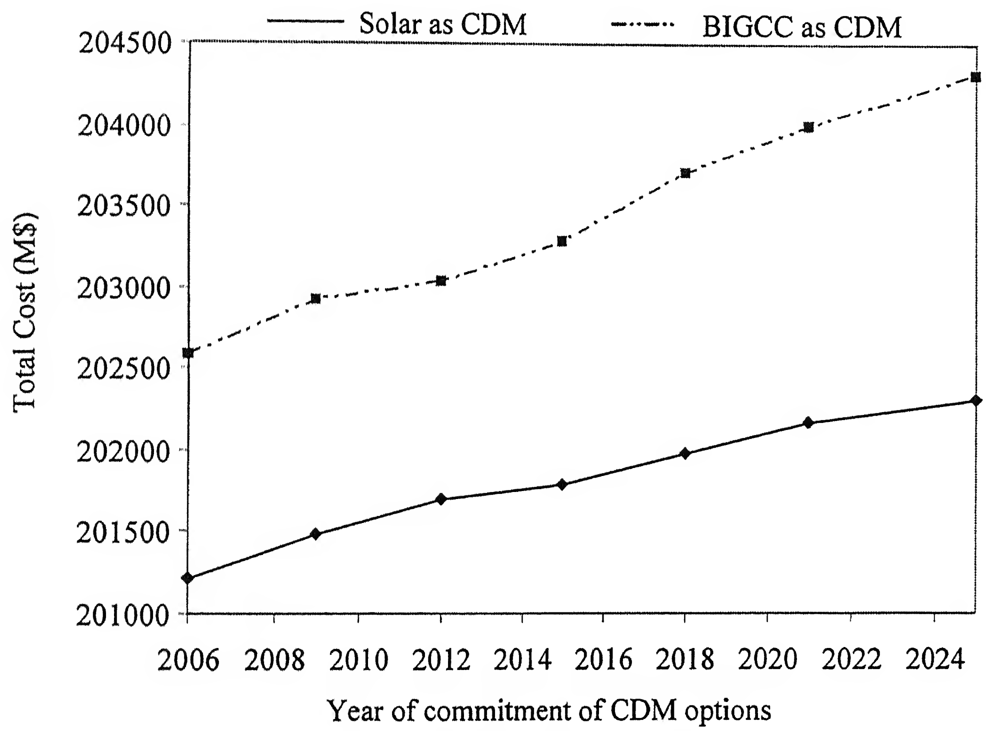

Fig 3.2: Effect of change in commitment year of CDM options on total cost for TRP baseline

Figures 3.2 and 3.3 show the effect of changing the commitment year of the solar and BIGCC as CDM options on the Total Cost (TC) and Marginal Abatement Cost (MAC), respectively in the TRP baseline. It is observed from these tables that by increasing the year of commitment for Solar and BIGCC power plants, TC increases every year. However,

MAC does not show any specific trend and is least in the year 2025 for Solar as CDM option and in the year 2018 for BIGCC CDM option.

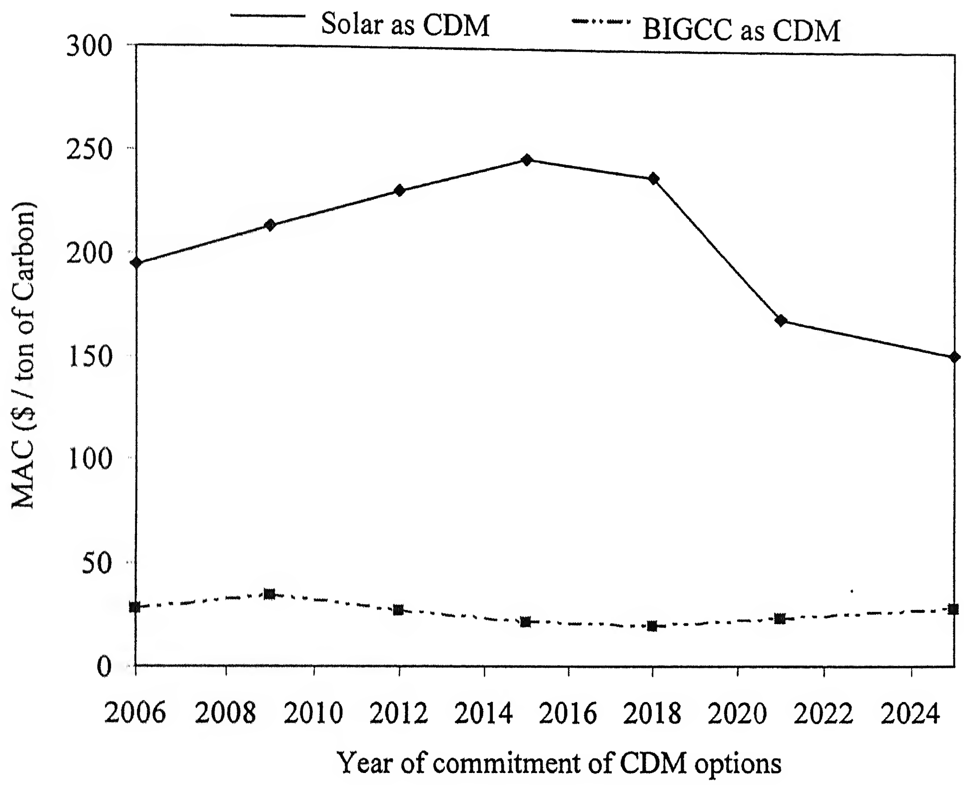

Fig 3.3: Effect of change in commitment year of CDM options on MAC for TRP baseline

b) For IRP case

Figures 3.4 and 3.5 show the impact of changing the commitment year of the solar and BIGCC as CDM options on Total Cost (TC) and Marginal Abatement Cost (MAC), respectively in the IRP baseline. It is observed from these tables that by increasing the year of commitment for Solar and BIGCC power plants, TC increases every year. However, MAC does not show any specific trend and is least in the year 2025 for Solar as CDM option and in the year 2018 for BIGCC as CDM option.

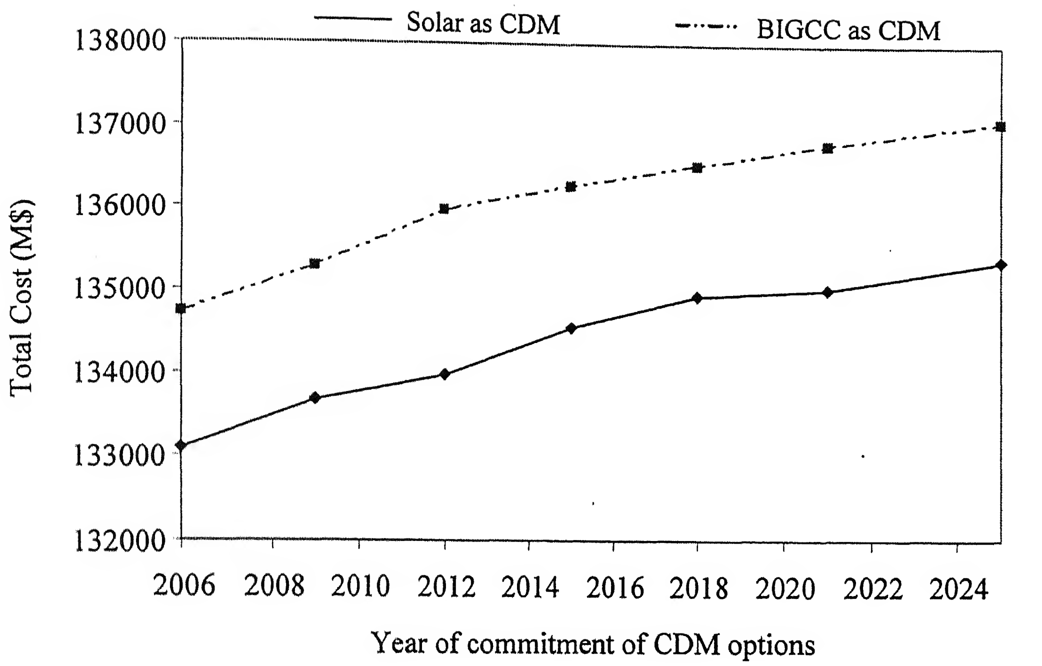

Fig 3.4: Effect of change in commitment year of CDM options on total cost for IRP baseline

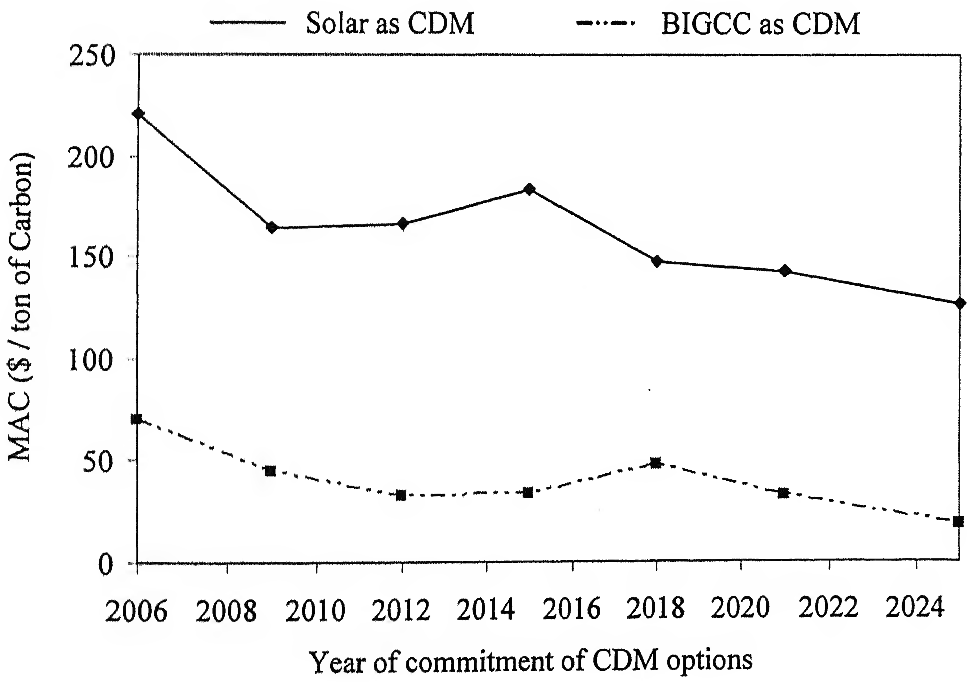

Fig 3.5: Effect of change in commitment year of CDM options on MAC for IRP baseline

3.6.2 Sensitivity of CO_2 emissions to changing year of commitment of the CDM options

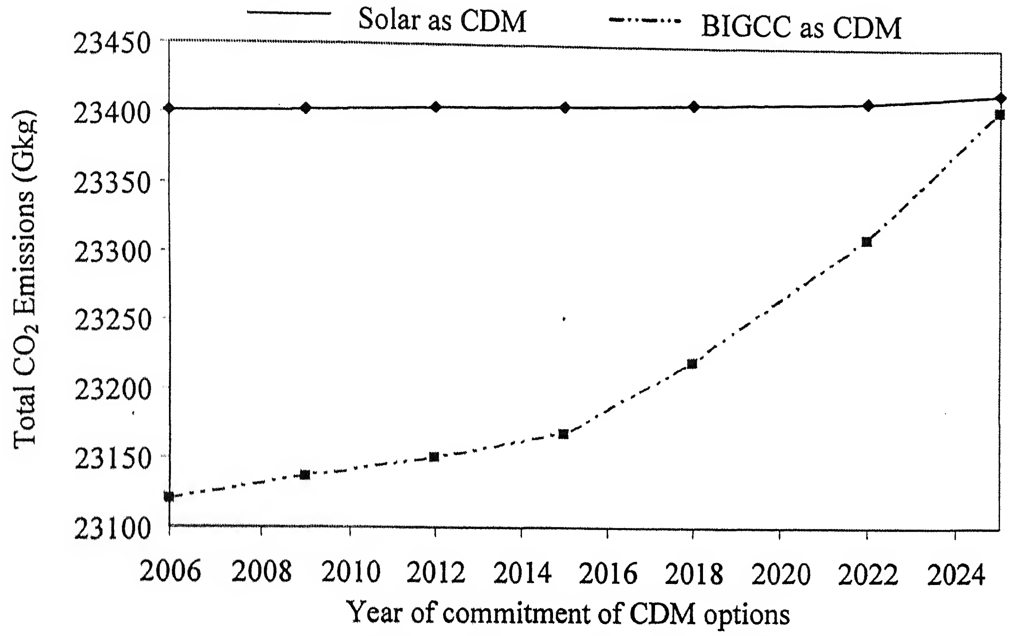

Fig 3.6: Effect of change in commitment year of CDM options on total CO_2 emissions for TRP baseline

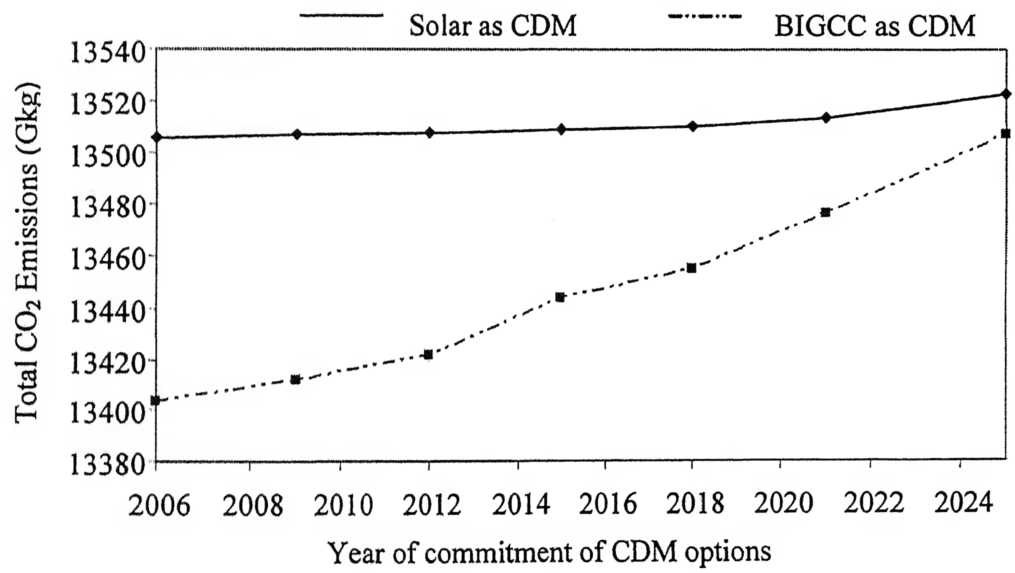

Fig 3.7: Effect of change in commitment year of CDM options on total CO_2 emissions for IRP baseline

Figures 3.6 and 3.7 show the effect of changing the commitment year of the Solar and BIGCC as CDM options on the total CO2 emissions in the TRP and IRP baseline, respectively. It is observed from these tables that by increasing the year of commitment for Solar and BIGCC power plants, CO2 emissions increase slightly in case of Solar and continuously in case of BIGCC as CDM options.

3.6.3 Sensitivity of SO_2 emissions to changing year of commitment of the CDM options

Figures 3.8 and 3.9 show the effect of changing the commitment year of the Solar and BIGCC as CDM options on the total SO_2 emissions in the TRP and IRP baseline, respectively. It is observed from these tables that by increasing the year of commitment for Solar, the SO_2 emissions increase marginally, whereas by changing the commitment year of BIGCC, SO_2 emissions increase sharply after the year 2015.

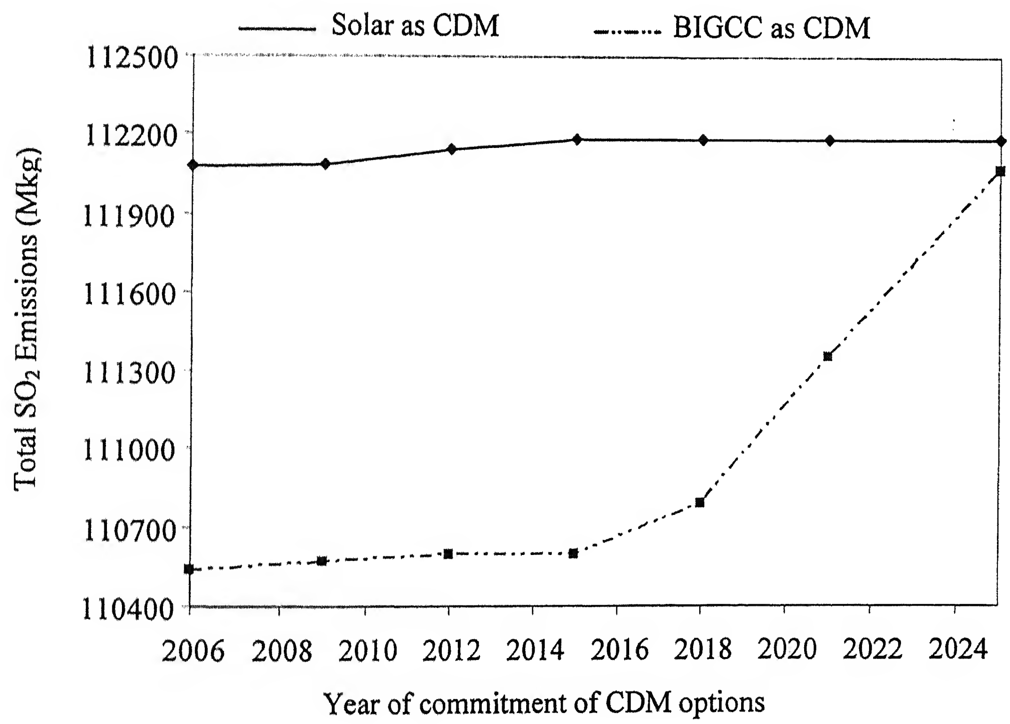

Fig 3.8: Effect of change in commitment year of CDM options on total SO_2 emissions for TRP baseline

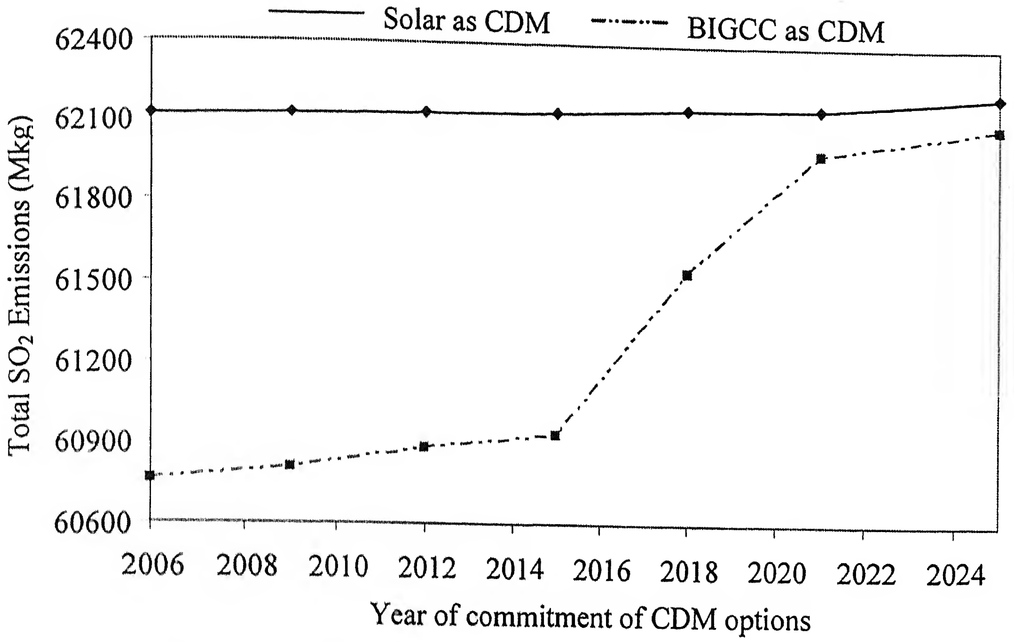

Fig 3.9: Effect of change in commitment year of CDM options on total SO_2 emissions for IRP baseline

3.6.4 Sensitivity of NO_X emissions to changing year of commitment of the CDM options

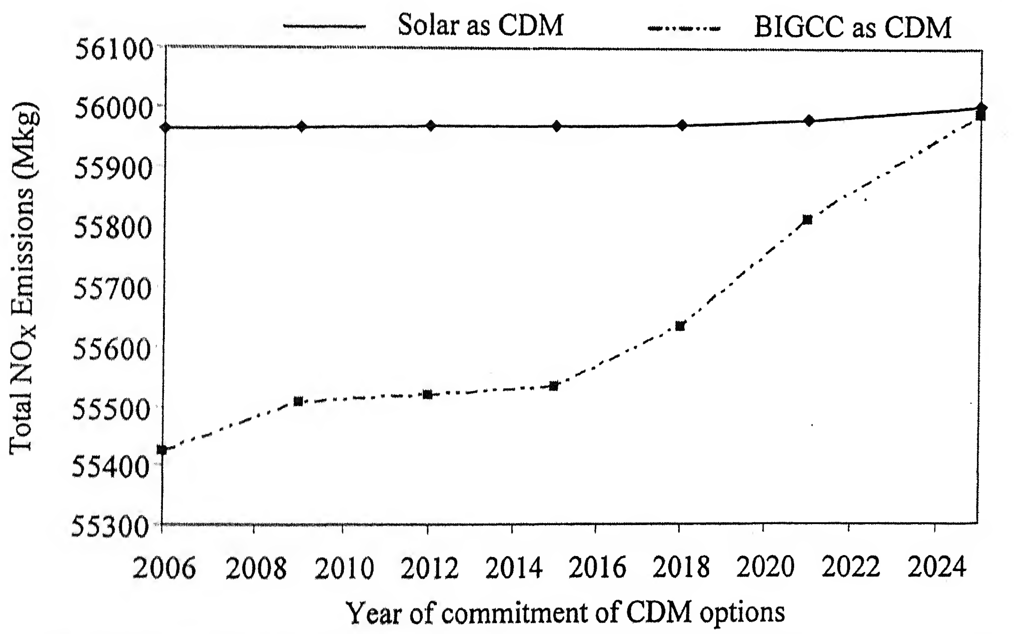

Fig 3.10: Effect of change in commitment year of CDM options on total NO_X emissions for TRP baseline

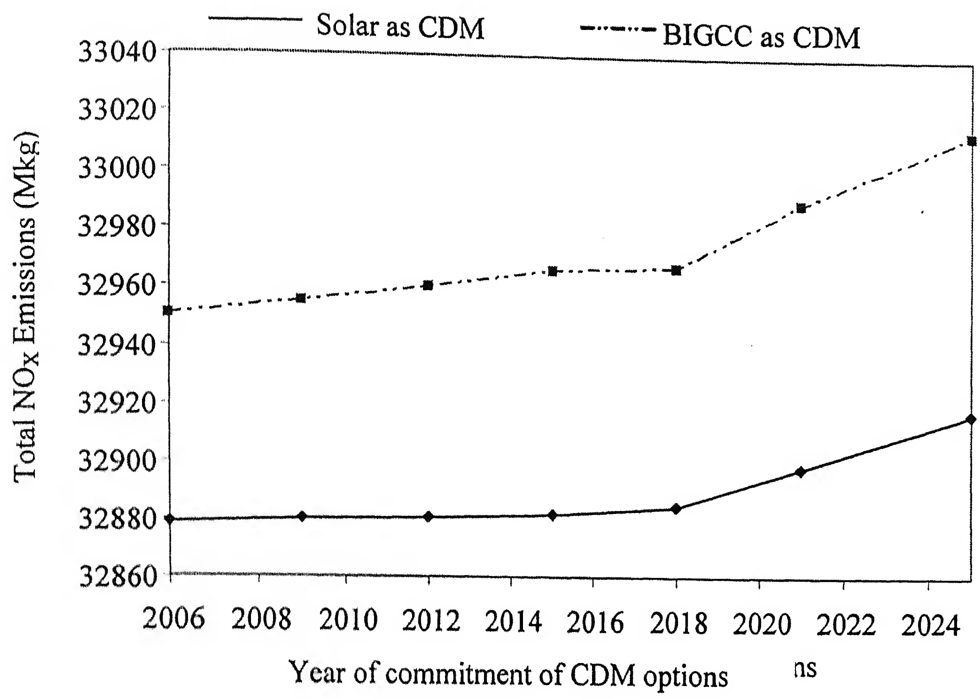

Fig 3.11: Effect of change in commitment year of CDM options on total NO_X emissions for IRP baseline

Figures 3.10 and 3.11 show the effect of changing the commitment year of the Solar and BIGCC as CDM options on the total NO_X emissions, in the TRP and IRP baseline respectively. It is observed from these tables that by increasing the year of commitment for Solar and BIGCC as CDM options, the NO_X emissions increase marginally up to the year 2018 and increase sharply thereafter.

3.7 Economics of CDM Projects at Different Baselines

3.7.1 Market prices and MAC's under different trading scenarios

To meet the specified curtailment of CO_2 emissions, Annex-B countries may purchase CER's (Certified Emission Reductions) from a Non Annex-B country. The Annex-B countries will choose to achieve their Kyoto Protocol targets by investing in Clean Development Mechanisms in one or more of the Non Annex-B countries, based upon the Marginal Abatement Cost (MAC) of the CDM projects in a specific Non Annex-B

country. MAC of CDM projects in a Non Annex-B country should be below the maximum permitted market price for emissions, for the Annex-B countries to invest in that particular country. Tables 3.16 and 3.17 exhibit market price of emission permits and MAC for some developed (Annex-B) countries under different trading scenarios [5].

Table 3.16: Market price of emission permits under different scenarios

Market price of permits ($/ton of carbon)	Scenarios
24	Full global trading
63	Global trading, Annex-B countries acting as monopoly and former Soviet Union (FSU) competing with Annex-B
108	Global trading, Annex-B countries and FSU acting as monopoly
114	Annex trading
142	Annex-B trading, FSU monopoly

Table 3.17: Marginal cost of abatement for some developed countries under different scenarios

Countries	$/ton of carbon (no OECD trading)	$/ton of carbon (OECD trading)
Japan	584.0	240
European Union	273.0	240
Other OECD countries	233.0	240
USA	186.0	240

By observing tables 3.16 and 3.17 and based on the results presented in section 3.5, economics of CDM options can be analyzed under different trading scenarios as given below. To be selected as a CDM project, MAC of a CDM option should be less than the maximum permeated MAC in at least one of the cases given in Tables 3.16 and 3.17 [27].

3.7.2 Full global trading (Scenario-1):

The least amongst MAC's of all the plausible CDM plants is 28.24 $/ton of Carbon, which is more than the market price of permits for the Full global trading scenario (24 $/ton

of Carbon). Hence, no project will be selected as CDM under the Full Global Trading Scenario.

3.7.3 Global trading, Annex-B countries acting as monopoly and Former Soviet Union (FSU) competing with Annex-B countries (Scenario-2):

Since the MAC of Solar projects in both TRP and IRP baselines is more than the market price of permits for trading scenario-2 (63$/ton of Carbon) throughout the planning horizon, the Solar projects will not qualify as CDM projects in this scenario. However, in the TRP base line, BIGCC projects qualify as CDM projects throughout the planning horizon in trading scenario-2, as their MAC is less than the market price of permits for trading scenario-2. In the IRP baseline, the BIGCC projects committed after 2006 qualify as CDM projects in trading scenario-2.

3.7.4 Global Trading, Annex-B countries and FSU acting as monopoly (Scenario-3):

Similar to trading scenario-2, Solar projects in TRP and IRP baselines do not qualify as CDM projects in trading scenario-3, throughout the planning horizon. In both TRP and IRP baselines, the BIGCC projects qualify as CDM projects throughout the planning horizon in trading scenario-3, as their MAC is less than the market price of permits for trading (103$/ton of Carbon) throughout the planning horizon.

3.7.5 Annex-B trading (Scenario-4):

In this trading scenario, Solar projects in TRP and IRP baselines do not qualify as CDM projects. BIGCC projects qualify as CDM projects throughout the planning horizon in both TRP and IRP baselines, as their MAC is less than the market price of permits for this scenario (114 $/ton of Carbon).

3.7.6 Annex-B trading, FSU monopoly (Scenario-5):

In this trading scenario, Solar projects in TRP baseline do not qualify as CDM projects. However, in IRP baseline, Solar projects committed after 2024 qualify as CDM projects. BIGCC projects qualify as CDM projects throughout the planning horizon in both TRP and IRP baselines in this trading scenario, as their MAC is less than the market price of permits (114 $/ton of Carbon).

3.7.7 Direct trading with OECD countries, no trading between the OECD countries (Scenario-A):

In the scenario of OECD trading, Japan and European Union can invest in India in Solar and BIGCC CDM options in both TRP and IRP baselines, regardless of the year in which these plants are committed. USA can invest in India in BIGCC as CDM projects in both TRP and IRP baselines. However, in case of Solar as CDM projects in TRP baseline committed after the year 2018, USA can invest in India. USA can invest in India in Solar as CDM projects, when they are committed in any year of the planning horizon except 2006 and 2015 for the IRP baseline. Other OECD countries can invest in India in BIGCC as CDM projects in both TRP and IRP baselines and in Solar as CDM projects in IRP baseline, throughout the planning horizon. In case of Solar as CDM projects in TRP baseline, other OECD countries can invest in India, when they are committed in any year of the planning horizon except the years 2015 and 2018.

3.7.8 Trading with group of OECD countries (Scenario-B):

In the scenario of OECD trading, Japan, USA, European Union and other OECD countries can invest in India in the following cases:

a) BIGCC as CDM projects in both TRP and IRP baselines throughout the planning horizon.
b) Solar as CDM projects in IRP baseline throughout the planning horizon.

c) Solar as CDM projects in TRP baseline, when these are committed in any year of the planning horizon except the year 2015.

3.8 Conclusions

This chapter has presented a detailed study of identifying the suitable CDM projects for the integrated Indian power system and analyzing their utility, cost and environmental implications. The study includes optimal generation expansion planning studies for six cases (three in TRP baseline and three in IRP baseline).

Based on these studies, Solar and BIGCC technologies have been identified as candidate CDM options. However, an analysis of utility, cost and environmental implications of these candidate CDM technologies reveal that BIGCC is a more promising technology for Clean Development Mechanism. The BIGCC technology as a CDM project is more effective in reducing the generation and capacity mix of coal plants which are the major source of Green House Gas emissions (CO_2 emissions in this study).

When the cost implications are analyzed, it is observed that the Marginal Abatement Cost (MAC) for BIGCC plants is much less than that for Solar plants, which makes them more preferred CDM technology for trading in various scenarios. It has also been observed that the BIGCC technology is much more effective in reducing the emissions of environmental pollutants like CO_2, SO_2 and NO_X, except in the case of NO_X emissions in the IRP baseline, where Solar technology is more effective.

The study also examines the economics of CDM projects, which clearly indicates that the BIGCC as a CDM project will be chosen by most of the investing countries in both the TRP and IRP baselines as the MAC of BIGCC as CDM projects is much less than the market price of permits of emissions in almost all the trading scenarios.

Chapter 4

Conclusions

Increased emissions of Green House Gases (GHGs) and other pollutants from power sector and its detrimental effects on the global and local environment have made this aspect to be included in the electric utility planning. In many countries of Asia, including India, power sector is at a stage of complete restructuring and reforms. During this time of transition, it is critical to determine how best to take advantage of the opportunities it presents to protect the environment and avert threats to public health and accordingly plan expansion of the power sector.

In this work, cost-effectiveness and environmental emission mitigation potential of Clean Development Mechanism (CDM) options has been studied and their impact on power system planning has been examined. The study has been carried out to identify potential CDM projects under the Traditional Resource Planning (TRP) and Integrated Resource Planning (IRP) perspectives on the integrated Indian power system network. The main findings of the study carried out in this thesis are given below:

1) All the candidate hydro plants got selected in both the TRP and IRP baselines.
2) Coal, Combined Cycle Gas Turbine (CCGT), Lignite and Wind power plants are almost fully selected in all the cases.
3) The plants which are not at all selected in the base case during the entire planning horizon for both TRP an IRP cases are Solar and BICC plants. Hence, these plants are identified as plausible CDM options.
4) The generation and capacity mix of Coal, Hydro, CCGT, Lignite, Oil, Nuclear, PFBC, IGCC and Wind plants have changed slightly when either Solar or BIGCC plants, as CDM options, are committed in their year of earliest availability.

5) The study on environmental implications of CDM options reveal that, the BIGCC is more effective than Solar in reducing the emissions of environmental pollutants like CO_2, SO_2 and NO_X, except in the case of NO_X emissions in the IRP baseline, where Solar technology is more effective.
6) The sensitivity analysis of total cost with respect to the change in the commitment year of the CDM options indicates that total cost increases as the year of commitment of the CDM options is delayed.
7) The sensitivity analysis of Marginal Abatement Cost (MAC) with respect to change in commitment year of the CDM options does not show any specific trend.
8) The sensitivity of CO_2, SO_2, and NO_X emissions to change in commitment year of the CDM options is very minimal in case of Solar as CDM option and significant for change in commitment year of BIGCC as CDM option.
9) The electricity price in case of Solar as CDM option is less than that in the case of BIGCC as CDM in both the TRP and IRP baselines.
10) The analysis of economics of CDM options indicate that none of the CDM options will be selected as a CDM project under the Full Global Trading Scenario, as their MACs are more than the market price of permits for emissions for this trading scenario.
11) The BIGCC, as CDM option, got selected as a CDM project in most of the Annex-B and OECD trading scenarios. BIGCC is found to be a more potential CDM project as compared to the solar plants.

As a consequence of the study carried out in this thesis, the following areas of further research work have been identified:

1) This study provides specific insight into identification of CDM projects and also analyzes the utility, cost and environmental implications of these projects. The identification of CDM projects are based on the MAC data given in [27] under different trading scenarios. For more realistic selection of CDM projects, it is

necessary to critically obtain these data in the present scenario and define carefully the baseline for CDM studies.

2) The Kyoto Protocol has addressed six green house gases. Only CO_2 has been considered for the present study. Further work may include some of the remaining GHGs in the utility planning.
3) In this study, the demand side data is obtained from a study for DSM planning for Gujarat and Uttar Pradesh by TERI. An extensive survey of DSM options will be required for most part of the country to achieve more practical results.
4) Indian power sector has also started extensive programmes on renovation and modernization (R&M) of power plants and reduction of transmission and distribution (T&D) losses. These require huge investment and may also be considered as CDM options.

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Appendix-A

Existing Thermal Plants Data

Name	Fuel type	Fuel con. ('000 Kg/ MWh)	Cal. value (KBtu /Kg)	CO2 emissions(Kg/ MWh)	SO2 emissions (Kg/ MWh)	NOX emissions (Kg/ MWh)	Cap. MW	Heat rate (KCal /KWh)	Op. cost ('000 $/KWh)	Annual maint. (hrs)	Fixed O&M costs ('000 $/MW month)
BADARPUR-1-3	COAL	0.8	17.5	1349.33	6.4	3.6	285	3528	0.0012	864	2
BADARPUR-4-5	COAL	0.7	17.5	1180.67	4.2	3.2	420	3087	0.0012	864	2
I.P.STATION-2	COAL	0.826	15	1272.04	6.6	3.2	249	3122	0.0012	864	2
RAJGHAT-1	COAL	0.82	13.5	1172.6	6.6	2.8	136	2790	0.0012	864	2
I.P.GT-1	GAS	0.221	34.52	504.5	0.4	1.5	282	1922	0.0008	1296	1.67
PRAGATI CCGT-1	GAS	0.221	34.52	504.5	0.4	1.5	330	1922	0.0008	1296	1.67
F'BAD EXTN.-1	COAL	0.945	18.5	1663.2	7.6	4.5	165	4406	0.0012	864	2
PANIPAT-1	COAL	0.85	16.5	1340.17	6.8	3.4	440	3534	0.0012	864	2
PANIPAT-5	COAL	0.75	16.5	1182.5	4.5	3	420	3119	0.0012	864	2
F'BAD CCGT-1	GAS	0.221	34.52	504.5	0.4	1.5	429	1922	0.0008	1296	1.67
PAMPORE GT-1	GAS	0.221	34.52	504.5	0.4	1.5	175	1922	0.0008	1296	1.67
GNDTP(BHATINDA)-1	COAL	0.74	17	1193.87	4.4	3.1	440	3170	0.0012	864	2
GHTP (LEH.MOH.)-1	COAL	0.7	17	1129.33	4.2	3	420	2999	0.0012	864	2
ROPAR-1	COAL	0.692	16.5	1091.05	4.2	2.8	1260	2877	0.0012	864	2
KOTA-1	COAL	0.65	17.5	1096.33	3.9	2.9	220	2867	0.0012	864	2
KOTA-3	COAL	0.55	17.5	927.67	2.2	2.4	630	2426	0.0012	864	2
R.A.P.S.-1	NUCLEAR	0.027	406.35	0	0	0	520	2765	0.0015	864	2
SURATGARH-1	COAL	0.812	13.5	1161.16	6.5	2.8	1000	2762	0.0012	864	2
RAMGARH GT-1	GAS	0.221	34.52	504.5	0.4	1.5	77	1922	0.0008	1296	1.67
ANTA GT-1	GAS	0.221	34.52	504.5	0.4	1.5	413	1922	0.0008	1296	1.67
OBRA-1	COAL	0.98	13.5	1401.4	7.8	3.2	200	3334	0.0012	864	2
OBRA-6	COAL	0.88	13.5	1258.4	7	2.9	282	2994	0.0012	864	2
OBRA-9	COAL	0.84	15	1293.6	6.7	3.2	1000	3175	0.0012	864	2
PANKI-2	COAL	0.85	14	1246.67	6.8	3	32	2999	0.0012	864	2
PANKI-3	COAL	0.85	14	1246.67	6.8	3	210	2999	0.0012	864	2
H'GANJ B-1	COAL	1.3	17.5	2192.67	15.6	5.8	80	5733	0.0012	864	2
H'GANJ B-3	COAL	1.1	17.5	1855.33	11	4.9	240	4851	0.0012	864	2
H'GANJ B-7	COAL	0.9	17.5	1518	7.2	4	105	3969	0.0012	864	2
PARICHA-1	COAL	0.89	13.5	1272.7	7.1	3	220	3028	0.0012	864	2
ANPARA-1	COAL	1	15	1540	8	3.8	630	3780	0.0012	864	2
ANPARA-4	COAL	0.5	15	770	2	1.9	1000	1890	0.0012	864	2
SINGRAULI STPS-1	COAL	0.7	15	1078	4.2	2.8	1000	2646	0.0012	864	2
SINGRAULI STPS-6	COAL	0.55	15	847	2.2	2.2	1000	2079	0.0012	864	2
RIHAND-1	COAL	0.6	15	924	3.6	2.4	1000	2268	0.0012	864	2
UNCHAHAR-1	COAL	0.7	13.5	1001	4.2	2.4	840	2381	0.0012	864	2
DADRI (NCTPP)-1	COAL	0.64	13.5	915.2	3.8	2.2	840	2177	.0.0012	864	2
TANDA-1	COAL	1.04	13.5	1487.2	10.4	3.5	440	3538	0.0012	864	2
AURAIYA GT-1	GAS	0.221	34.52	504.5	0.4	1.5	652	1922	0.0008	1296	1.67
DADRI GT-1	GAS	0.221	34.52	504.5	0.4	1.5	818	1922	0.0008	1296	1.67
N.A.P.S.-1	NUCLEAR	0.027	406.35	0	0	0	440	2765	0.0015	864	2
DHUVARAN-1	OIL	0.3	39.68	935	0.6	2.4	256	3000	0.0012	1296	2
DHUVARAN-5	OIL	0.3	39.68	935	0.6	2.4	280	3000	0.0012	1296	2
UKAI-1	COAL	1	15	1540	8	3.7	240	3780	0.0012	864	2
UKAI-3	COAL	0.8	15	1232	2	1.9	610	3024	0.0012	864	2
GANDHI NAGAR-1	COAL	0.9	15	1386	7.2	3.6	240	3402	0.0012	864	2
GANDHI NAGAR-3	COAL	0.69	15	693	1.8	1.8	420	2434	0.0012	864	2
UTRAN GT-1	GAS	0.221	34.52	504.5	0.4	1.5	144	1922	0.0008	1296	1.67

HAZIRA CCCP-1	GAS	0.221	34.52	504.5	0.4	1.5	156	1922	0.0008	1296	1.67
WANAKBORI-1	COAL	0.69	14	1012	4.1	2.5	1260	2434	0.0012	864	2
G.S.E.C.L.(G.5)-1	COAL	0.58	17	935.73	3.5	2.5	420	2485	0.0012	864	2
SIKKA REP.-1	COAL	0.606	16.5	955.46	3.6	2.5	240	2520	0.0012	864	2
KUTCH LIG.-1	LIGNITE	1.21	11.11	1286.63	12.1	3.4	215	3388	0.0012	864	2
DHUVARAN GT-1	GAS	0.221	34.52	504.5	0.4	1.5	54	1922	0.0008	1296	1.67
A.E.CO.-15	COAL	0.536	22	1021.97	2.1	2.9	60	2972	0.0012	864	2
VATWA GT-1	GAS	0.221	34.52	504.5	0.4	1.5	101	1922	0.0008	1296	1.67
ESSAR GT IMP.-1	GAS	0.221	34.52	504.5	0.4	1.5	90	1922	0.0008	1296	1.67
SABARMATI-1	COAL	0.484	22	922.83	1.9	2.6	220	2683	0.0012	864	2
G.I.P.C.L. GT-1	GAS	0.221	34.52	504.5	0.4	1.5	311	1922	0.0008	1296	1.67
SURAT LIG.-1	LIGNITE	1.15	11.11	1222.83	11.5	3.2	250	3220	0.0012	864	2
G.T.E. CORP.-1	GAS	0.221	34.52	504.5	0.4	1.5	655	1922	0.0008	1296	1.67
KAWAS GT-1	GAS	0.221	34.52	504.5	0.4	1.5	644	1922	0.0008	1296	1.67
GANDHAR GT-1	GAS	0.221	34.52	504.5	0.4	1.5	648	1922	0.0008	1296	1.67
KAKRAPARA-1	NUCLEAR	0.027	406.35	0	0	0	440	2765	0.0015	864	2
SATPURA-1	COAL	0.789	13.5	1128.27	4.7	2.7	315	2684	0.0012	864	2
SATPURA-6	COAL	0.817	13.5	1168.31	6.5	2.8	830	2779	0.0012	864	2
KORBA-II-1	COAL	0.971	13.5	1388.53	7.8	3.3	160	3303	0.0012	864	2
KORBA-III-1	COAL	0.902	13.5	1289.86	7.2	3.1	240	3069	0.0012	864	2
KORBA-WEST-1	COAL	0.738	15	1136.52	4.4	2.7	840	2790	0.0012	864	2
AMAR KANTAK-1	COAL	0.9	17.5	1518	7.2	4.1	50	3969	0.0012	864	2
AMAR KANTAK EXT-1	COAL	0.7	17.5	1180.67	4.2	3.2	240	3087	0.0012	864	2
SANJAY GANDHI-1	COAL	0.8	15	1232	6.4	3.2	840	3024	0.0012	864	2
KORBA STPS-1	COAL	0.75	15	1155	4.5	3	600	2835	0.0012	864	2
KORBA STPS-4	COAL	0.6	15	924	3.6	2.4	500	2268	0.0012	864	2
KORBA STPS-5	COAL	0.6	15	924	3.6	2.4	500	2268	0.0012	864	2
KORBA STPS-6	COAL	0.6	15	924	3.6	2.4	500	2268	0.0012	864	2
VINDH'CHAL STPS-1	COAL	0.63	15	970.2	3.8	2.5	1260	2381	0.0012	864	2
VINDH'CHAL STPS-7	COAL	0.6	15	924	3.6	2.4	500	2268	0.0012	864	2
VINDH'CHAL STPS-8	COAL	0.6	15	924	3.6	2.4	500	2268	0.0012	864	2
NASIK-1	COAL	1	15	1540	8	3.8	280	3780	0.0012	864	2
NASIK-3	COAL	0.8	15	1232	1.6	1.5	630	3024	0.0012	864	2
KORADI-1	COAL	1	15	1540	8	3.8	460	3780	0.0012	864	2
KORADI-5	COAL	0.8	15	1232	2	1.9	620	3024	0.0012	864	2
K'KHEDA II-1	COAL	0.761	13.5	1088.23	4.6	2.6	840	2589	0.0012	864	2
PARAS-2	COAL	0.86	17	1387.47	6.9	3.7	58	3684	0.0012	864	2
BHUSAWAL-1	COAL	1.2	13.5	1716	12	4.2	58	4082	0.0012	864	2
BHUSAWAL-2	COAL	1	13.5	1209	1.6	1.4	420	3402	0.0012	864	2
PARLI-1	COAL	0.9	15	1386	7.2	3.3	60	3402	0.0012	864	2
PARLI-3	COAL	0.7	15	1078	4.2	2.6	630	2646	0.0012	864	2
CHANDRAPUR-1	COAL	1.2	13.5	1716	12	4	840	4082	0.0012	864	2
CHANDRAPUR-5	COAL	0.6	13.5	572	1.6	1.3	500	2040	0.0012	864	2
CHANDRAPUR-6	COAL	0.6	13.5	682	1.6	1.3	500	2040	0.0012	864	2
CHANDRAPUR-7	COAL	6	13.5	682	1.6	1.3	500	2040	0.0012	864	2
URAN GT-1	GAS	0.221	34.52	504.5	0.4	1.5	912	1922	0.0008	1296	1.67
TROMBAY-4	OIL	0.3	39.68	935	0.6	2.4	150	3000	0.0012	1296	2
TROMBAY-5	OIL	0.3	39.68	935	0.6	2.4	500	3000	0.0012	1296	2
TROMBAY-6	OIL	0.3	39.68	935	0.6	2.4	500	3000	0.0012	1296	2
TROMBAY GT-1	GAS	0.221	34.52	504.5	0.4	1.5	180	1922	0.0008	1296	1.67
DHANU-1	COAL	0.538	17	867.97	2.2	2.3	500	2305	0.0012	864	2
DHABOL GT-1	GAS	0.221	34.52	504.5	0.4	1.5	740	1922	0.0008	1296	1.67
TARAPUR-1	NUCLEAR	0.027	406.35	0	0	0	320	2765	0.0015	864	2
K'GUDEM-1	COAL	1.3	12.5	1763.67	15.6	4.1	240	4095	0.0012	864	2
K'GUDEM-5	COAL	0.942	12.5	1277.98	7.5	3	430	2967	0.0012	864	2
K'GUDEM-9	COAL	0.6	12.5	704	2	1.6	500	2040	0.0012	864	2
VIJAYWADA-1	COAL	0.697	13.5	996.71	4.2	2.4	1260	2371	0.0012	864	2
R'GUNDEM - B-1	COAL	0.82	15	1262.8	6.6	3	63	3100	0.0012	864	2
NELLORE-1	COAL	1.06	15	1632.4	10.6	4.2	30	4007	0.0012	864	2
RAYAL SEEMA-1	COAL	0.83	13.5	1186.9	6.6	2.8	420	2824	0.0012	864	2
VIJESWARAN GT-1	GAS	0.221	34.52	504.5	0.4	1.5	273	1922	0.0008	1296	1.67

BANDEL-1	COAL	1.1	19.5	2016.67	11	5.3	320	5405	0.0012	864	2
BANDEL-5	COAL	0.6	19.5	550	0.6	1.4	210	3000	0.0012	864	2
SANTALDIH-1	COAL	0.699	22	1332.76	4.2	3.7	480	3875	0.0012	864	2
KASBA GT-1	GAS	0.221	34.52	504.5	0.4	1.5	40	1922	0.0008	1296	1.67
SILIGURI GT-1	GAS	0.221	34.52	504.5	0.4	1.5	20	1922	0.0008	1296	1.67
HALDIA GT-1	GAS	0.221	34.52	504.5	0.4	1.5	40	1922	0.0008	1296	1.67
KOLAGHAT-1	COAL	0.803	16.5	1266.06	6.4	3.3	1260	3339	0.0012	864	2
BAKRESWAR-1	COAL	0.55	17.5	927.67	2.2	2.5	430	2426	0.0012	864	2
D.P.L.-1	COAL	1.05	18.5	1848	10.5	4.8	390	4895	0.0012	864	2
MULAJORE-2	COAL	0.8	19.5	2116.4	11.1	6.5	60	6154	0.0012	864	2
NEWCOSSIPORE-1	COAL	0.8	19.5	2288	12	6.4	130	3931	0.0012	864	2
TITAGARH-1	COAL	0.58	19.5	1063.33	3.5	2.8	240	3931	0.0012	864	2
SOUTHERN REPL.-1	COAL	0.623	18.5	1096.48	3.7	2.8	136	2904	0.0012	864	2
BUDGE BUDGE-1	COAL	0.556	17	897.01	2.2	2.4	500	2382	0.0012	864	2
FARAKKA STPS-1	COAL	0.86	12	1135.2	6.9	2.6	600	2601	0.0012	864	2
FARAKKA STPS-4	COAL	0.6	12.5	792	3.6	1.8	500	1890	0.0012	864	2
FARAKKA STPS-5	COAL	0.6	12.5	792	3.6	1.8	500	1890	0.0012	864	2
CHANDRAPUR-1	COAL	1	17.5	1686.67	8	4.5	60	4410	0.0012	864	2
NAMRUP GT-1	GAS	0.221	34.52	504.5	0.4	1.5	104	1922	0.0008	1296	1.67
BONGAIGAON-1	COAL	1.05	17.5	1771	10.5	4.7	240	4631	0.0012	864	2
LAKWA GT-1	GAS	0.221	34.52	504.5	0.4	1.5	120	1922	0.0008	1296	1.67
D.L.F. PVT-1	GAS	0.221	34.52	504.5	0.4	1.5	25	1922	0.0008	1296	1.67
MOBILE GAS T-G-1	GAS	0.221	34.52	504.5	0.4	1.5	21	1922	0.0008	1296	1.67
LEIMAKHONG DG-1	OIL	0.2	39.68	935	0.4	2.4	36	2000	0.0012	1296	2
KATHALGURI GT-1	GAS	0.221	34.52	504.5	0.4	1.5	294	1922	0.0008	1296	1.67
AGARTALA GT-1	GAS	0.221	34.52	504.5	0.4	1.5	84	1922	0.0008	1296	1.67
BARAMURA GT-1	GAS	0.221	34.52	504.5	0.4	1.5	38	1922	0.0008	1296	1.67
ROKHIA GT-1	GAS	0.221	34.52	504.5	0.4	1.5	69	1922	0.0008	1296	1.67
PANIPAT-7(NEW)	COAL	0.75	16.5	1182.5	4.5	3	250	3119	0.0012	864	2
PANIPAT-8(NEW)	COAL	0.75	16.5	1182.5	4.5	3	250	3119	0.0012	864	2
GOVINDWAL (NEW)	COAL	0.5	22	953.33	2	2.7	500	2772	0.0012	864	2
GURU HGTPP-II1	COAL	0.7	17	1129.33	4.2	2.8	250	2999	0.0012	864	2
GURU HGTPP-II2	COAL	0.7	17	1129.33	4.2	2.8	250	2999	0.0012	864	2
KOTA ST-4(NEW)	COAL	0.55	17.5	927.67	2.2	2.4	195	2426	0.0012	864	2
BARSINGSAR -1(C)	LIGNITE	0.8	11.11	850.67	12.1	2.8	250	2250	0.0012	864	2
SURATGARH III(C)	COAL	0.812	11	1042.07	6.5	2.8	250	2251	0.0012	864	2
BARSINGSAR-2(C)	LIGNITE	1.21	11.11	1286.63	12.1	2.8	250	3388	0.0012	864	2
RAMGARH GAS-2(C)	GAS	0.221	34.52	504.5	0.4	1.5	37	1922	0.0008	1296	1.67
MATAHANIA CCPP1C	GAS	0.221	34.52	504.5	0.4	1.5	140	1922	0.0008	1296	1.67
RAPP-5	NUCLEAR	0.027	406.35	0	0	0	220	2765	0.0015	864	2
RAPP-6 (NEW)	NUCEAR	0.027	406.35	43.56	0	0	220	2765	0.0015	864	2
DADRI II(NEW)	COAL	0.64	13.5	915.2	3.8	2.2	490	2177	0.0012	864	2
PARICHHAEXT1(NEW	COAL	0.905	13.5	1294.15	7.2	3.1	210	3079	0.0012	864	2
UNCHAHAR III(NEW	COAL	0.7	13.5	1001	4.2	2.4	210	2381	0.0012	864	2
ANPARA 'C'-1(C)	COAL	0.686	15	1056.44	4.1	2.6	500	2593	0.0012	864	2
ANPARA 'C'-2(C)	COAL	0.686	15	1056.44	4.1	2.6	500	2593	0.0012	864	2
RIHAND-II-1	COAL	0.65	15	1001	3.9	2.7	500	2457	0.0012	864	2
RIHAND-II-2	COAL	0.65	15	1001	3.9	2.7	500	2457	0.0 12	864	2
BHILAI TPS1-2C	COAL	0.707	15	1088.78	4.2	2.7	574	2672	0.0012	864	2
BINA TPS1-2C	COAL	0.7	13.5	1001	4.2	2.8	578	2381	0.0012	864	2
KORBA-WEST-PVT2C	COAL	0.714	15	1099.56	4.3	2.8	420	2699	0.0012	864	2
PENCH TPS1-2C	COAL	0.5	22	953.33	2	2.8	500	2772	0.0012	864	2
RAIGARH1-2C	COAL	0.5	22	953.33	2	2.8	550	2772	0.0012	864	2
AKRIMOTA LIG.(C)	LIGNITE	1.21	11.11	1286.63	12.1	3	125	3388	0.0012	864	2
AKRIMOTA LIG.(C)	LIGNITE	1.21	11.11	1286.63	12.1	3	125	3388	0.0012	864	2
KLTPS EXT.(NEW)	LIGNITE	1.21	11.11	1286.63	12.1	3	75	3388	0.0012	864	2
SIPAT-1(C)	COAL	0.5	22	953.33	2	2.8	660	2772	0.0012	864	2
SIPAT-2(C)	COAL	0.5	22	953.33	2	2.8	660	2772	0.0012	864	2
SIPAT-3(C)	COAL	0.5	22	953.33	2	2.8	660	2772	0.0012	864	2
PARLI TPP EX-I	COAL	0.71	15	1093.4	4.3	2.6	250	2684	0.0012	864	2
JAMNAGAR(REFRES)	GAS	0.221	34.52	504.5	0.4	1.5	500	1922	0.0008	1296	1.67

KHAP'KHEDA3	COAL	0.768	13.5	1098.24	4.6	2.5	500	2613	0.0012	864	2
DHUVARAN (NEW)	GAS	0.221	34.52	504.5	0.4	1.5	107	1922	0.0008	1296	1.67
AHWR (NEW)	NUCLEAR	0.027	406.35	0	0	0	235	2765	0.0015	864	2
BHADRAVATI-2C	COAL	0.5	22	953.33	2	2.7	541	2772	0.0012	864	2
BHADRAVATI-1C	COAL	0.5	22	953.33	2	2.7	541	2772	0.0012	864	2
DABHOL CCGT-I-1	GAS	0.221	34.52	504.5	0.4	1.5	370	1922	0.0008	1296	1.67
DABHOL CCGT-I-2	GAS	0.221	34.52	504.5	0.4	1.5	370	1922	0.0008	1296	1.67
DABHOL CCGT-II1	GAS	0.221	34.52	504.5	0.4	1.5	361	1922	0.0008	1296	1.67
DABHOL CCGT-II2	GAS	0.221	34.52	504.5	0.4	1.5	361	1922	0.0008	1296	1.67
TAPP-3	NUCLEAR	0.027	406.35	0	0	0	540	2765	0.0015	864	2
TAPP-4	NUCLEAR	0.027	406.35	0	0	0	540	2765	0.0015	864	2
PATALGANGA C	GAS	0.221	34.52	504.5	0.4	1.5	447	1922	0.0008	1296	1.67
BIRSINGPUR (NEW)	COAL	0.826	15	1272.04	6.6	2.8	500	3122	0.0012	864	2
KORBA EAST-PVT2C	COAL	0.936	13.5	1338.48	7.5	3.1	420	3184	0.0012	864	2
VINDHYACHAL II1-	COAL	0.63	17	1016.4	3.8	2.7	500	2699	0.0012	864	2
VINDHYACHALIII-N	COAL	0.63	17	1016.4	3.8	2.7	500	2699	0.0012	864	2
RATLAM DIESEL	OIL	0.2	39.68	935	0.4	2.4	118	2000	0.0012	1296	2
RAMAGUNDAM BPL-C	COAL	0.747	15	1150.38	4.5	2.8	520	2824	0.0012	864	2
RAMAGUNDAM-IIIC	COAL	0.747	15	1150.38	4.5	2.8	500	2824	0.0012	864	2
SIMHADRI TPS-1	COAL	0.6	13.5	858	3.6	2	500	2041	3.0076	864	2
VIZAG TPS-1	COAL	0.5	22	953.33	2	2.7	520	2772	0.0012	864	2
VIZAG TPS-2	COAL	0.5	22	953.33	2	2.7	520	2772	0.0012	864	2
PEDDAPURAM2	GAS	0.221	34.52	504.5	0.4	1.5	78	1922	0.0008	1296	1.67
VEMAGIRI CCGT (C	GAS	0.221	34.52	504.5	0.4	1.5	370	1922	0.0008	1296	1.67
GAUTAMI CCGT(NEW	GAS	0.221	34.52	504.5	0.4	1.5	464	1922	0.0008	1296	1.67
SPECTRUM EXT(SC)	GAS	0.221	34.52	504.5	0.4	1.5	360	1922	0.0008	1296	1.67
MANGLORE-TPS-4(C	COAL	0.5	22	953.33	2	2.7	506	2772	0.0012	864	2
MANGLORE-TPS-5(C	COAL	0.5	22	953.33	2	2.7	506	2772	0.0012	864	2
K'PATNAM B-C	COAL	0.5	22	953.33	2	2.7	520	2772	0.0012	864	2
CUDDALORE-I,1 C	COAL	0.5	22	953.33	2	2.7	660	2772	0.0012	864	2
CUDDALORE-I,2 C	COAL	0.5	22	953.33	2	2.7	660	2772	0.0012	864	2
TUTICORIN-IV C	COAL	0.633	15	974.82	3.8	2.5	525	2393	0.0012	864	2
RAICHUR-7	COAL	0.641	15	987.14	3.9	2.5	210	2423	0.0012	864	2
KANINMINK (C)	GAS	0.221	34.52	504.5	0.4	1.6	108	1922	0.0008	1296	1.67
HASSAN (NEW)	GAS	0.221	34.52	504.5	0.4	1.6	189	1922	0.0008	1296	1.67
BHARAT FORGE	GAS	0.221	34.52	504.5	0.4	1.6	50	1922	0.0008	1296	1.67
KAIGA XT.U-3	NUCLEAR	0.027	406.35	0	0	0	220	2765	0.0015	864	2
KAIGA XT.U-4	NUCLEAR	0.027	406.35	0	0	0	220	2765	0.0015	864	2
KAIGA XT-5	NUCLEAR	0.027	406.35	0	0	0	220	2765	0.0015	864	2
KAIGA XT-6	NUCLEAR	0.027	406.35	0	0	0	220	2765	0.0015	864	2
VYPEEN LNG1(C)	GAS	0.221	34.52	504.5	0.4	1.6	339	1922	0.0008	1296	1.67
VYPEEN LNG2 (C)	GAS	0.221	34.52	504.5	0.4	1.6	340	1922	0.0008	1296	1.67
KANNUR CCGT2 (C)	GAS	0.221	34.52	504.5	0.4	1.5	258	1922	0.0008	1296	1.67
KANNUR CCGT1 (C)	GAS	0.221	34.52	504.5	0.4	1.5	255	1922	0.0008	1296	1.67
COCHIN REF	GAS	0.221	34.52	504.5	0.4	2.3	522	1922	0.0008	1296	1.67
KARAIKAL (NEW)	GAS	0.221	34.52	504.5	0.4	1.6	100	1922	0.0008	1296	1.67
KONASEEMA (NEW)	GAS	0.221	34.52	504.5	0.4	1.6	445	1922	0.0008	1296	1.67
NEYVELI-FST EXT2	LIGNITE	1.21	11.11	1286.63	12.1	3	210	3388	0.0012	864	2
NEYVELI-II (NEW)	LIGNITE	1.21	11.11	1286.63	12.1	3	500	3388	0.0012	864	2
N.MADRAS-III-C	COAL	0.78	13.5	1115.4	4.7	2.6	525	2654	0.0012	864	2
PFBR (NEW)	NUCLEAR	0.027	406.35	0	0	0	500	2765	0.0015	864	2
RAYL.SEMA-II-2	COAL	0.699	13.5	999.57	4.2	2.8	210	2378	0.0012	864	2
RAYL.SEMA-II-1	COAL	0.699	13.5	999.57	4.2	2.8	210	2378	0.0012	864	2
TALCHER II1C	COAL	0.6	13.5	2002	16.8	4.9	500	2040	0.0012	864	2
TALCHER II-2C	COAL	0.6	13.5	2002	16.8	4.9	500	2040	0.0012	864	2
JOJOBERA (NEW)	COAL	0.5	22	953.33	2	2.8	120	2772	0.0012	864	2
BIHTA TPP(NEW)	COAL	0.5	22	953.33	2	2.8	135	2772	0.0012	864	2
KAHALGAON-II(NEW	COAL	0.91	15	1401.4	7.3	3.6	660	3440	0.0012	864	2
KAHALGAON-III(NEW	COAL	0.91	15	1401.4	7.3	3.6	660	3440	0.0012	864	2
NOR. K.PURA NEW1	COAL	0.5	22	953.33	2	2.8	660	2772	0.0012	864	2
NOR. K.PURA NEW2	COAL	0.5	22	953.33	2	2.8	660	2772	0.0012	864	2

NOR. K.PURA NEW3	COAL	0.5	22	953.33	2	2.8	660	2772	0.0012	864	2
BARH (NEW)	COAL	0.5	22	953.33	2	2.8	660	2772	0.0012	864	2
MUZAFFAR XT-1	COAL	1	15	1540	8	3.7	500	3780	0.0012	864	2
MAITHON R1-4NEW	COAL	0.5	22	953.33	2	2.8	500	2772	0.0012	864	2
MAITHON R1-5NEW	COAL	0.5	22	953.33	2	2.8	500	2772	0.0012	864	2
MEZIA-4 (NEW)	COAL	0.69	16.5	1087.9	4.1	2.8	210	2869	0.0012	864	2
CHANDRAPUR-7NEW	COAL	0.747	17.5	1259.94	4.5	3.3	500	3294	0.0012	864	2
DUBRI TPS-C	COAL	0.5	22	953.33	2	2.7	500	2772	0.0012	864	2
IB-VALLEY-3-C	COAL	0.843	11	1081.85	6.7	2.3	210	2337	0.0012	864	2
IB-VALLEY-4-C	COAL	0.843	11	1081.85	6.7	2.3	210	2337	0.0012	864	2
MEZIA 5	COAL	0.7	16.5	1103.67	4.2	2.8	250	2911	0.0012	864	2
MEZIA 6	COAL	0.7	16.5	1103.67	4.2	2.8	250	2911	0.0012	864	2
IB-VALLEY5	COAL	0.843	11	1081.85	6.7	2.3	250	2337	0.0012	864	2
IB-VALLEY6	COAL	0.843	11	1081.85	6.7	2.3	250	2337	0.0012	864	2
BAKRESHWAR4-5(N)	COAL	0.55	17.5	927.67	2.2	2.5	420	2426	0.0012	864	2
BALAGARH TPS-1C	COAL	0.65	17.5	1096.33	3.9	2.9	250	2867	0.0012	864	2
BALAGARH TPS-2C	COAL	0.65	17.5	1096.33	3.9	2.9	250	2867	0.0012	864	2
SAGARDIGHI - I	COAL	0.5	22	953.33	2	2.8	250	2772	0.0012	864	2
SAGARDIGHI - II	COAL	0.5	22	953.33	2	2.8	250	2772	0.0012	864	2
TENUGHAT EX 5	COAL	0.7	15	1078	4.2	2.8	210	2646	0.0012	864	2
TENUGHAT EX 6	COAL	0.7	15	1078	4.2	2.8	210	2646	0.0012	864	2
TENUGHAT EX 7	COAL	0.7	15	1078	4.2	2.8	210	2646	0.0012	864	2
LAKWA WH (SC)	GAS	0.221	34.52	504.5	0.4	2.4	38	1922	0.0008	1296	1.67
TRIPURA GAS (C)	GAS	0.221	34.52	504.5	0.4	2.3	500	1922	0.0008	1296	1.67
MANIPUR DG	OIL	0.2	39.68	935	0.4	2.4	18	2000	0.0012	1296	2
MENDIPATH.HFO(SC	OIL	0.2	39.68	935	0.4	2.4	24	2000	0.0012	1296	2
BYRNIHAT HFO(N)	OIL	0.2	39.68	935	0.4	2.4	24	2000	0.0012	1296	2
BAIRABI HFO(NEW)	OIL	0.2	39.68	935	0.4	2.4	23	2000	0.0012	1296	2
RAPP 7 (NEW)	NUCLEAR	0.027	406.35	0	0	0	540	2765	0.0015	864	2
RAPP-8 (NEW)	NUCLEAR	0.027	406.35	0	0	0	540	2765	0.0015	864	2
PARLI TPP EX-II	COAL	0.71	15	1093.4	4.3	2.6	250	2684	0.0012	864	2
PANKI EXT	COAL	0.883	14	1295.07	7.1	3.2	210	3115	0.0012	864	2
PARICHA EXT2	COAL	0.905	17	1460.07	7.2	3.9	210	3877	0.0012	864	2
GIRAL	LIGNITE	0.8	11.11	850.67	12.1	3	250	2250	0.0012	864	2
PANIPAT REF.	COAL	0.775	16.5	1221.92	4.7	3.2	250	3222	0.0012	864	2
ROSA	COAL	0.5	19.5	916.67	2	2.5	567	2457	0.0012	864	2
CHAMBAL CCGT	LIGNITE	0.8	11.11	850.67	12.1	3	166	2250	0.0012	864	2
UTRANG CCGT	COAL	0.5	19.5	916.67	2	2.5	300	2457	0.0012	864	2
BHUSAVAL EXT 1	COAL	0.709	14	1039.87	4.3	2.5	500	2501	0.0012	864	2
BHUSAVAL EXT 2	COAL	0.709	14	1039.87	4.3	2.5	500	2501	0.0012	864	2
PARAS EXT	COAL	0.782	17	1261.63	4.7	3.4	250	3350	0.0012	864	2
NASIK EXT	COAL	0.642	15	988.68	3.9	2.6	500	2427	0.0012	864	2
KORBA-W EXT	COAL	0.714	14	1047.2	4.3	2.6	500	2519	0.0012	864	2
MALWA	COAL	0.5	19.5	916.67	2	2.5	1000	2457	0.0012	864	2
AMAR KANTAK EXT	COAL	0.792	17.5	1335.84	4.8	3.6	210	3493	0.0012	864	2
GHOGHA 1	LIGNITE	0.8	11.11	850.67	12.1	3	125	2250	0.0012	864	2
GHOGHA 2	LIGNITE	0.8	11.11	850.67	12.1	3	250	2250	0.0012	864	2
PIPAVAV	GAS	0.221	34.52	504.5	0.4	1.5	615	1922	0.0008	1296	1.97
SAVALI REF.	COAL	0.5	19.5	916.67	2	2.5	500	2457	0.0012	864	2
MANGROL EXT	LIGNITE	0.8	11.11	850.67	12.1	3	250	2250	0.0012	864	2
AMRAVATI	COAL	0.5	19.5	916.67	2	2.5	500	2457	0.0012	864	2
KORBA EAST	COAL	0.718	13.5	1026.74	4.3	2.4	1070	2443	0.0012	864	2
GUNA CCGT	LIGNITE	0.8	11.11	850.67	12.1	3	330	2250	0.0012	864	2
KUNDANKULAM-1	COAL	0.5	19.5	916.67	2	2.5	1000	2457	0.0012	864	2
KUNDANKULAM-2	COAL	0.5	19.5	916.67	2	2.5	1000	2457	0.0012	864	2
KUNDANKULAM-3	COAL	0.5	19.5	916.67	2	2.5	1000	2457	0.0012	864	2
CHENNAI PET	COAL	0.5	19.5	916.67	2	2.5	500	2457	0.0012	864	2
SHRIMUSHAN	LIGNITE	0.8	11.11	850.67	12.1	3	250	2250	0.0012	864	2
JAYANKUNDAM	LIGNITE	0.8	11.11	850.67	12.1	3	500	2250	0.0012	864	2
BARH-2	COAL	0.5	19.5	916.67	2	2.5	660	2457	0.0012	864	2
BARH-3	COAL	0.5	19.5	916.67	2	2.5	660	2457	0.0012	864	2

HIRMA ST-1	COAL	0.5	19.5	916.67	2	2.5	1440	2457	0.0012	864	2
HIRMA ST-2	COAL	0.5	19.5	916.67	2	2.5	1440	2457	0.0012	864	2
HIRMA ST-3	COAL	0.5	19.5	916.67	2	2.5	1440	2457	0.0012	864	2
AMGURI CCGT	GAS	0.221	34.52	504.5	0.4	1.5	90	1922	0.0008	1296	1.67
VIJAYAWADA EXT 4	COAL	0.702	14	1029.6	4.2	2.5	660	2477	0.0012	864	2
IP REPLACE	GAS	0.221	34.52	504.5	0.4	1.5	330	1922	0.0008	1296	1.67
SIPAT-4(C)	COAL	0.5	22	953.33	2	2.8	660	2772	0.0012	864	2
KORBA EAST	COAL	0.718	13.5	1026.74	4.3	2.4	420	2443	0.0012	864	2
VEMBER CCGT	GAS	0.221	34.52	504.5	0.4	1.5	1873	1922	0.0008	1296	1.67

Appendix-B

Existing Hydro Plants Data

NAME	Capacity (Mw)	Operating cost (K$/Mwhr)	Fixed O&M cost (K$/Mwhr)	Available energy in season 1 (Mwhr)	Available energy in season 2 (Mwhr)	Availability fraction
W.Y.CANAL-6	48.0	0.0000	1.390	75000	169000	0.87
ANDHRA U-1-3	17.0	0.0000	1.390	19000	25000	0.87
HP SMALL	27.0	0.0000	1.390	43000	61000	0.87
BAIRA SIUL-3	180.0	0.0000	1.390	233000	416000	0.87
BANER+THIR+GAJ	27.0	0.0000	1.390	43000	61000	0.87
BASPA II-3	300.0	0.0000	1.390	482000	724000	0.87
BASSI-4	60.0	0.0000	1.390	110000	152000	0.87
BINWA	6.0	0.0000	1.390	14000	20000	0.87
CHAMERA-I-3	540.0	0.0000	1.390	908000	1204000	0.87
CHAMERA-II1	100.0	0.0000	1.390	140000	210000	0.87
CHAMERA-II2-3	300.0	0.0000	1.390	280000	420000	0.87
GIRI BATA-2	60.0	0.0000	1.390	107000	98000	0.87
LARJI 1-3	126.0	0.0000	1.390	131000	196000	0.87
KASHANG 1 (SC)	66.0	0.0000	1.390	79000	119000	0.87
GHANVI	23.0	0.0000	1.390	28000	41000	0.87
DHAMVARI SUNDA(C	70.0	0.0000	1.390	121000	181000	0.87
NATHPAJHAKRI1-6	1500.0	0.0000	1.390	1990000	2986000	0.87
SANJAY BHABA-3	120.0	0.0000	1.390	168000	334000	0.87
MALANA	86.0	0.0000	1.390	148000	222000	0.87
MALANA-II (C)	100.0	0.0000	1.390	166000	249000	0.87
BAGLIHAR-1-C	150.0	0.0000	1.390	353000	530000	0.87
BAGLIHAR-2-C	150.0	0.0000	1.390	353000	530000	0.87
BAGLIHAR-3-C	150.0	0.0000	1.390	353000	530000	0.87
CHENANI	23.0	0.0000	1.390	45000	68000	0.87
DULHASTI-3	390.0	0.0000	1.390	772000	1157000	0.87
SAWALKOT- HE (C)	600.0	0.0000	1.390	1535000	2302000	0.87
J&K-SMALL	6.0	0.0000	1.390	8000	11000	0.87
KARGIL	4.0	0.0000	1.390	2000	4000	0.87
LOWER JHELUM	105.0	0.0000	1.390	111000	232000	0.87
GANDERBAL	15.0	0.0000	1.390	37000	56000	0.87
PARNAI	38.0	0.0000	1.390	96000	144000	0.87
SALAL-I-3	345.0	0.0000	1.390	630000	842000	0.87
SALAL-II-3	345.0	0.0000	1.390	625000	842000	0.87
SEWA-III	9.0	0.0000	1.390	19000	28000	0.87
SEWA-II (new)	120.0	0.0000	1.390	226000	338000	0.87
RAMPUR (new)	400.0	0.0000	1.390	480000	720000	0.87
UPPER SINDH-I	22.0	0.0000	1.390	42000	62000	0.87
UPPER SINDH-II	70.0	0.0000	1.390	65000	97000	0.87
UPPER SINDH-III	35.0	0.0000	1.390	32000	49000	0.87
URI-4	480.0	0.0000	1.390	605000	1176000	0.87

MOHORA	9.0	0.0000	1.390	32000	47000	0.87
ANANDPUR SAHIB4	134.0	0.0000	1.390	263000	389000	0.87
BEAS DEHAR-6	990.0	0.0000	1.390	1316000	1846000	0.87
BEAS PONG-6	360.0	0.0000	1.390	575000	941000	0.87
BHAKRA (LB+RB)-5	1250.0	0.0000	1.390	1405000	3287000	0.87
GA'WAL+KOTLA-1-3	156.0	0.0000	1.390	271000	783000	0.87
MUKERIAN-A-C	207.0	0.0000	1.390	436000	786000	0.87
SHAHPUR KHANDI	168.0	0.0000	1.390	277000	416000	0.87
SHANAN-1-5	110.0	0.0000	1.390	197000	292000	0.87
RANJIT SAGAR1-4	600.0	0.0000	1.390	546000	818000	0.87
UBDC -6	90.0	0.0000	1.390	129000	216000	0.87
SYL CANAL (C)	50.0	0.0000	1.390	127000	190000	0.87
ANOOPGARH	9.0	0.0000	1.390	14000	22000	0.87
JAWAHAR SAGAR-1-2	100.0	0.0000	1.390	24000	116000	0.87
MAHI-2+4	140.0	0.0000	1.390	14000	36000	0.87
R.P.SAGAR-1+2	172.0	0.0000	1.390	19000	164000	0.87
RAJ-SMALL	10.0	0.0000	1.390	18000	17000	0.87
CHIBRO-4	240.0	0.0000	1.390	316000	451000	0.87
DHAKRANI-1-3	34.0	0.0000	1.390	59000	84000	0.87
DHALIPUR-3	51.0	0.0000	1.390	102000	118000	0.87
DHAULIGANGA-I-2	280.0	0.0000	1.390	454000	680000	0.87
KHARA-3	72.0	0.0000	1.390	124000	221000	0.87
KHATIMA GANGA	41.0	0.0000	1.390	60000	106000	0.87
KHODRI-4	120.0	0.0000	1.390	147000	222000	0.87
KULHAL ST-IV-3	30.0	0.0000	1.390	56000	90000	0.87
CHILLA-4	144.0	0.0000	1.390	149000	370000	0.87
MANERI BHALI-I3	90.0	0.0000	1.390	64000	345000	0.87
MANERI BH-II-1	76.0	0.0000	1.390	94000	140000	0.87
MANERI BH-II-4	228.0	0.0000	1.390	280000	421000	0.87
MATATILA-3	30.0	0.0000	1.390	51000	86000	0.87
OBRA-3-H	99.0	0.0000	1.390	114000	300000	0.87
RAMGANGA-3	198.0	0.0000	1.390	71000	402000	0.87
RIHAND-6	300.0	0.0000	1.390	256000	792000	0.87
SOBLA	6.0	0.0000	1.390	10000	14000	0.87
TANAKPUR-1-3	120.0	0.0000	1.390	173000	262000	0.87
TEHRI ST I-1	250.0	0.0000	1.390	287000	430000	0.87
TEHRI ST I-2	250.0	0.0000	1.390	287000	430000	0.87
TEHRI ST I-3&4	500.0	0.0000	1.390	573000	860000	0.87
UP-SMALL	43.0	0.0000	1.390	41000	103000	0.87
KOTESHWAR 1-4	400.0	0.0000	1.390	1971000	2957000	0.87
VISHNUPRAYAG1(C)	200.0	0.0000	1.390	824000	1236000	0.87
VISHNUPRAYAG2(C)	200.0	0.0000	1.390	824000	1236000	0.87
GANDHI SAGAR+4,5	115.0	0.0000	1.390	15000	88000	0.87
TALA HEP1&2	510.0	0.0000	1.390	784000	1176000	0.87
TALA HEP3&4	510.0	0.0000	1.390	784000	1176000	0.87
MARIKHEDA HE (SC	40.0	0.0000	1.390	29000	44000	0.87
OMKARESHWAR1-4 C	520.0	0.0000	1.390	515000	773000	0.87
KANHER	4.0	0.0000	1.390	3000	5000	0.87
UKAI-4	300.0	0.0000	1.390	129000	291000	0.87
UKAI LBC	5.0	0.0000	1.390	8000	11000	0.87

BHANDARADARA-1-2	44.0	0.0000	1.390	4000	10000	0.87
BHATSA-1	15.0	0.0000	1.390	11000	46000	0.87
BHIRA TR-2	80.0	0.0000	1.390	23000	42000	0.87
MAH-SMALL	12.0	0.0000	1.390	10000	14000	0.87
DUDHAGANGA 2	24.0	0.0000	1.390	22000	34000	0.87
ELDARI-1-2	23.0	0.0000	1.390	15000	38000	0.87
PANSHET(K.VASLA)	16.0	0.0000	1.390	12000	18000	0.87
BHIVPURI-6	72.0	0.0000	1.390	142000	212000	0.87
BHIRA-6	132.0	0.0000	1.390	259000	389000	0.87
KOYANA DAM PH-2	40.0	0.0000	1.390	5000	98000	0.87
KOYANA III-4,5,8	880.0	0.0000	1.390	771000	1599000	0.87
KOYANA ST 4/1	250.0	0.0000	1.390	116000	174000	0.87
KOYANA ST 4/2	250.0	0.0000	1.390	116000	174000	0.87
KOYANA ST 4/3	250.0	0.0000	1.390	116000	174000	0.87
KOYANA ST 4/4	250.0	0.0000	1.390	116000	174000	0.87
MANIKDOH	6.0	0.0000	1.390	8000	13000	0.87
PAITHON	12.0	0.0000	1.390	2000	6000	0.87
PAWANA	10.0	0.0000	1.390	6000	8000	0.87
PENCH HYDRO	160.0	0.0000	1.390	105000	178000	0.87
SARDAR SAROVAR2	200.0	0.0000	1.390	220000	329000	0.87
SARDAR SAROVAR3	200.0	0.0000	1.390	220000	329000	0.87
SARDAR SAROVAR4	600.0	0.0000	1.390	839000	1259000	0.87
SURYA	6.0	0.0000	1.390	8000	13000	0.87
TILLARI	60.0	0.0000	1.390	38000	74000	0.87
UJJANI PSS	12.0	0.0000	1.390	3000	15000	0.87
VAITRANA	60.0	0.0000	1.390	2000	123000	0.87
BHATGAR-VIR	25.0	0.0000	1.390	10000	38000	0.87
WARNA-2	16.0	0.0000	1.390	15000	23000	0.87
BANSAGAR-1-3	405.0	0.0000	1.390	372000	371000	0.87
BANSAGAR-4	20.0	0.0000	1.390	36000	55000	0.87
BAV-II(NEW)	37.0	0.0000	1.390	41000	62000	0.87
BARGI-1-2	90.0	0.0000	1.390	144000	220000	0.87
BIRSINGPUR-HYD	20.0	0.0000	1.390	31000	5000	0.87
HASDEO BANGO 1-3	120.0	0.0000	1.390	83000	150000	0.87
MAHESHWAR-1 (C)	240.0	0.0000	1.390	196000	293000	0.87
INDIRA SAGAR1	125.0	0.0000	1.390	185000	277000	0.87
INDIRA SAGAR2-7	750.0	0.0000	1.390	1109000	1663000	0.87
INDIRA SAGAR8	125.0	0.0000	1.390	186000	278000	0.87
GHATGHAR PSS	250.0	0.0000	1.390	100000	300000	0.87
PURLIA PSS	900.0	0.0000	1.390	680000	1020000	0.87
SARDAR SAROVAR	200.0	0.0000	1.390	262000	394000	0.87
MAHESHWAR-2-5 (C	160.0	0.0000	1.390	130000	196000	0.87
JURALA PRIYA-C	157.0	0.0000	1.390	147000	220000	0.87
JURALAPRIYA-C	78.0	0.0000	1.390	73000	109000	0.87
NAG SAGAR TL.(C)	50.0	0.0000	1.390	90000	137000	0.87
AP-SMALL	30.0	0.0000	1.390	130000	200000	0.87
BALIMELA-DPH	60.0	0.0000	1.390	66000	98000	0.87
DONKARAYI	25.0	0.0000	1.390	33000	108000	0.87
LOWER SILERU-1-4	460.0	0.0000	1.390	333000	980000	0.87
NAG. SAGAR LB	60.0	0.0000	1.390	50000	17000	0.87

NAG. SAGAR RB	90.0	0.0000	1.390	94000	43000	0.87
NAG.SAGAR2-8+PH1	810.0	0.0000	1.390	516000	1009000	0.87
U.KRISHNA(NEW)	810.0	0.0000	1.390	186000	279000	0.87
ALMATI DAM(NEW)1	290.0	0.0000	1.390	480000	720000	0.87
NIZAMSAGAR	10.0	0.0000	1.390	11000	18000	0.87
PENNA AB-1-2	20.0	0.0000	1.390	16000	50000	0.87
POCHAMPAD-1-3	27.0	0.0000	1.390	60000	67000	0.87
SINGUR HE	15.0	0.0000	1.390	27000	40000	0.87
SRISAILAM-1-7	770.0	0.0000	1.390	1168000	1868000	0.87
UPPER SILERU-1-4	240.0	0.0000	1.390	98000	340000	0.87
BHADRA RBC-II	6.0	0.0000	1.390	9000	13000	0.87
BHADRA-3PH	39.0	0.0000	1.390	33000	75000	0.87
GHAT PRABHA-1-2	32.0	0.0000	1.390	16000	70000	0.87
JOG-1-8	120.0	0.0000	1.390	65000	360000	0.87
KALINADI-I-1-6	810.0	0.0000	1.390	470000	2097000	0.87
SUP DAM-1-2	100.0	0.0000	1.390	65000	360000	0.87
KAR -SMALL	3.0	0.0000	1.390	3000	5000	0.87
LINGANAMAKKI-1-2	55.0	0.0000	1.390	59000	216000	0.87
MALLAPUR	9.0	0.0000	1.390	1000	24000	0.87
MUNIRABAD-1-3	27.0	0.0000	1.390	37000	63000	0.87
SHARAVATHY-1-10	891.0	0.0000	1.390	1097000	4136000	0.87
SHIMSHA	17.0	0.0000	1.390	19000	43000	0.87
SHIVSAMUDRAM-1-10	42.0	0.0000	1.390	17000	48000	0.87
SHIVPUR	18.0	0.0000	1.390	31000	74000	0.87
T'BHADR DAM+HAMPI	72.0	0.0000	1.390	92000	133000	0.87
VARAHI-1-2	230.0	0.0000	1.390	284000	816000	0.87
VARAHI-MANI DAM	9.0	0.0000	1.390	16000	24000	0.87
IDDUKI-1-6	780.0	0.0000	1.390	369000	1927000	0.87
IDMALYAR-1-2	75.0	0.0000	1.390	100000	229000	0.87
KAKKAD-1&2	50.0	0.0000	1.390	104000	157000	0.87
KALLADA-1&2	15.0	0.0000	1.390	21000	48000	0.87
MANIAR	10.0	0.0000	1.390	12000	19000	0.87
KUTIYADI-1-3	75.0	0.0000	1.390	174000	93000	0.87
KUTIYADI EXTN	50.0	0.0000	1.390	30000	45000	0.87
LOWER PERIYAR	180.0	0.0000	1.390	270000	275000	0.87
NERIAMANGLAM	45.0	0.0000	1.390	99000	165000	0.87
PALLIVASAL	38.0	0.0000	1.390	55000	111000	0.87
PANIAR	30.0	0.0000	1.390	54000	115000	0.87
PORINGALKUTTU -I	32.0	0.0000	1.390	73000	101000	0.87
PORINGALKUTHU-II	16.0	0.0000	1.390	15000	23000	0.87
KUTIYADI (NEW)	100.0	0.0000	1.390	120000	180000	0.87
SABRIGIRI-1-6	300.0	0.0000	1.390	348000	990000	0.87
SERGULAM	48.0	0.0000	1.390	50000	83000	0.87
SHOLAYAR	54.0	0.0000	1.390	43000	153000	0.87
ADIRAPALLI-C	163.0	0.0000	1.390	114000	170000	0.87
ALIYAR	60.0	0.0000	1.390	67000	117000	0.87
TAMILNADU SMALL	3.0	0.0000	1.390	6000	9000	0.87
KODAYAR-1	100.0	0.0000	1.390	45000	267000	0.87
KUNDAH 1-10	555.0	0.0000	1.390	412000	1289000	0.87
BHAWANI KATH.(SC	90.0	0.0000	1.390	124000	186000	0.87

L.BHAVANI+DAM RBC	16.0	0.0000	1.390	15000	27000	0.87
LOWER METTUR-1-8	120.0	0.0000	1.390	174000	256000	0.87
METTUR DAM+TUNNEL	240.0	0.0000	1.390	218000	490000	0.87
MOYAR-1-3	36.0	0.0000	1.390	42000	106000	0.87
PAPANASAM	28.0	0.0000	1.390	35000	90000	0.87
PERIYAR-1-4	140.0	0.0000	1.390	194000	293000	0.87
KALLADA	15.0	0.0000	1.390	25200	37800	0.87
PYKARA	72.0	0.0000	1.390	93000	256000	0.87
PYKARA ULT.-1	50.0	0.0000	1.390	65000	97000	0.87
PYKARA ULT.-2&3	100.0	0.0000	1.390	65000	97000	0.87
SANKARPATHY	30.0	0.0000	1.390	21000	136000	0.87
SATHNUR DAM	8.0	0.0000	1.390	11000	16000	0.87
SERVALAR	20.0	0.0000	1.390	10000	24000	0.87
SHOLAYAR-1-2	95.0	0.0000	1.390	157000	227000	0.87
SURLIAR	35.0	0.0000	1.390	34000	59000	0.87
VAIGAI MICRO	6.0	0.0000	1.390	10000	11000	0.87
KADAM PARIAI-1-4	400.0	0.0000	1.390	88000	99000	0.87
EAST GANDAK-1&2	15.0	0.0000	1.390	4000	20000	0.87
EAST GANDAK-3	5.0	0.0000	1.390	12000	17000	0.87
KOEL KARO-1-3(C)	345.0	0.0000	1.390	679000	1019000	0.87
KOEL KARO-4-7(C)	366.0	0.0000	1.390	36000	54000	0.87
KOSI	20.0	0.0000	1.390	2000	53000	0.87
PANCHET HILL	80.0	0.0000	1.390	102000	39000	0.87
SONE EAST LINK	4.0	0.0000	1.390	4000	4000	0.87
SONE WEST CANAL	6.0	0.0000	1.390	6000	9000	0.87
SUBEREKHA-1-2	130.0	0.0000	1.390	52000	43000	0.87
CHANDIL HE	8.0	0.0000	1.390	15000	23000	0.87
MAITHON-2-3	63.0	0.0000	1.390	43000	87000	0.87
TEESTA DAM3-4(N)	300.0	0.0000	1.390	549000	823000	0.87
FARAKKA BAR-C	125.0	0.0000	1.390	236000	353000	0.87
KAMENG 1-2 (C)	300.0	0.0000	1.390	720000	1080000	0.87
KAMENG 3-4 (C)	300.0	0.0000	1.390	720000	1080000	0.87
BALIMELA 6	360.0	0.0000	1.390	340000	666000	0.87
BALIMELA-ST-II	150.0	0.0000	1.390	120000	180000	0.87
HIRAKUD-I+II	307.0	0.0000	1.390	302000	286000	0.87
MACHKUND	115.0	0.0000	1.390	148000	521000	0.87
RENGALI	250.0	0.0000	1.390	385000	336000	0.87
UPPER INDRA-2	300.0	0.0000	1.390	356000	534000	0.87
UPPER INDRA-4	300.0	0.0000	1.390	400000	600000	0.87
UPPER KOLAB-4	320.0	0.0000	1.390	169000	348000	0.87
LOWER LAGYAP	12.0	0.0000	1.390	33000	50000	0.87
RANGIT-II1	20.0	0.0000	1.390	45000	68000	0.87
RANGIT-II2	40.0	0.0000	1.390	91000	136000	0.87
RATHONGCHU-1	10.0	0.0000	1.390	28000	43000	0.87
RATHONGCHU-2	20.0	0.0000	1.390	56000	85000	0.87
UPPER RONGNICHU	8.0	0.0000	1.390	18000	26000	0.87
JALDHAKA	35.0	0.0000	1.390	29000	64000	0.87
RAMMAM ST-I1	12.0	0.0000	1.390	22000	32000	0.87
RAMMAM ST-I2	24.0	0.0000	1.390	43000	65000	0.87
RAMMAM-1-4	50.0	0.0000	1.390	111000	123000	0.87

SIKKIM-SMALL	12.0	0.0000	1.390	7000	10000	0.87
TEESTA-FALL1	22.0	0.0000	1.390	44000	66000	0.87
TEESTA-FALL2	23.0	0.0000	1.390	44000	66000	0.87
TEESTA-FALL3	23.0	0.0000	1.390	44000	66000	0.87
TEESTA-V	510.0	0.0000	1.390	874000	1310000	0.87
WB-SMALL+TILAYYA	14.0	0.0000	1.390	4000	7000	0.87
RANGANADI-3	405.0	0.0000	1.390	248000	373000	0.87
TAGO	4.5	0.0000	1.390	6000	9000	0.87
KARBI-L.BORP.-2	100.0	0.0000	1.390	95000	143000	0.87
KOPILI-4	200.0	0.0000	1.390	186000	409000	0.87
KOPILI-EXT	25.0	0.0000	1.390	45000	68000	0.87
LOKTAK-3	105.0	0.0000	1.390	146000	405000	0.87
LOKTAK D/S	90.0	0.0000	1.390	155000	232000	0.87
K KULAI	60.0	0.0000	1.390	49000	116000	0.87
KHANDONG	50.0	0.0000	1.390	95000	136000	0.87
UMIAM-UMSR	54.0	0.0000	1.390	51000	125000	0.87
UMIAM-UMTRU IV	60.0	0.0000	1.390	95000	149000	0.87
UMTRU	11.0	0.0000	1.390	19000	54000	0.87
TUIRIAL	60.0	0.0000	1.390	96000	145000	0.87
TUIVAI1-C	210.0	0.0000	1.390	215000	324000	0.87
DOYANG-3	75.0	0.0000	1.390	130000	194000	0.87
LIKIMRO	16.0	0.0000	1.390	41000	61000	0.87
GUMTI	15.0	0.0000	1.390	18000	52000	0.87
NER_MICRO HYDRO	22.0	0.0000	1.390	18000	27000	0.87
MYNTDU - C	84.0	0.0000	1.390	128000	192000	0.87
BAIRABI HYDRO	80.0	0.0000	1.390	124000	186000	0.87
PARBATI-I	750.0	0.0000	1.390	1120000	1680000	0.87
PARBATI-II	800.0	0.0000	1.390	1245000	1863000	0.87
PARBATI-III	520.0	0.0000	1.390	791000	1186430	0.87
PAKALDUL	1000.0	0.0000	1.390	1436000	2154000	0.87
BURSAR	1020.0	0.0000	1.390	650400	975600	0.87
NIMBOO BAZGO	45.0	0.0000	1.390	96000	144000	0.87
CHAMERA-III	231.0	0.0000	1.390	443268	664902	0.87
SUBANSIRI UPPER	2000.0	0.0000	1.390	2632516	3948774	0.87
SUBANSIRI MIDDLE	1600.0	0.0000	1.390	1949952	2924928	0.87
SUBANSIRI LOWER I	1000.0	0.0000	1.390	1484318	2225682	0.87
SUBANSIRI LOWER I	1000.0	0.0000	1.390	1484318	2225682	0.87
KOLDAM -1 (C)	200.0	0.0000	1.390	307000	460000	0.87
KOLDAM -2 (C)	200.0	0.0000	1.390	307000	460000	0.87
KOLDAM -3 (C)	200.0	0.0000	1.390	307000	460000	0.87
KOLDAM -4 (C)	200.0	0.0000	1.390	307000	460000	0.87
LOHARI NAGPALA	520.0	0.0000	1.390	775600	1163400	0.87
PALANMERI	416.0	0.0000	1.390	630400	945600	0.87
UHL-ST III	100.0	0.0000	1.390	156476	234714	0.87
CHIRGAON	46.0	0.0000	1.390	67600	101400	0.87
PUDITAL LASS	36.0	0.0000	1.390	60000	90000	0.87
TANGU ROMAI	44.0	0.0000	1.390	92000	148000	0.87
KASHANG-II	94.0	0.0000	1.390	118000	177000	0.87
SAWARA KUDDU	144.0	0.0000	1.390	133200	199800	0.87
SORANG	100.0	0.0000	1.390	118800	178200	0.87

TIDONG	100.0	0.0000	1.390	156800	235200	0.87
RENUKA DAM	40.0	0.0000	1.390	84800	127200	0.87
NEW GANDERBAL	45.0	0.0000	1.390	86800	130200	0.87
SITKARI KULAN	84.0	0.0000	1.390	181200	271800	0.87
UBDC+MHP-III	105.0	0.0000	1.390	188800	283200	0.87
SHAHPURKHANDI EXT	56.0	0.0000	1.390	76800	115200	0.87
ALLAIN DUHANGAN	192.0	0.0000	1.390	271272	406908	0.87
KARCHAM WANGTOO U	500.0	0.0000	1.390	912000	1368000	0.87
KARCHAM WANGTOO U	500.0	0.0000	1.390	912000	1368000	0.87
BUDHIL	70.0	0.0000	1.390	114400	171600	0.87
BHARMOUR	45.0	0.0000	1.390	100400	150600	0.87
SAINJ	100.0	0.0000	1.390	210000	315000	0.87
SRINAGAR	330.0	0.0000	1.390	558800	838200	0.87
KADANA	240.0	0.0000	1.390	19600	29400	0.87
MEKADATU	400.0	0.0000	1.390	752000	1128000	0.87
SHIVASAMUDRAM	270.0	0.0000	1.390	636000	954000	0.87
MAHADAYI	320.0	0.0000	1.390	254000	381000	0.87
P KUTTY	240.0	0.0000	1.390	257600	386400	0.87
KOEL KARO	710.0	0.0000	1.390	400000	600000	0.87
RAMMAM ST IV	60.0	0.0000	1.390	122400	183600	0.87
RANGANADI-II	130.0	0.0000	1.390	154960	232440	0.87
LOWER KOPILI	150.0	0.0000	1.390	244820	367230	0.87
TIPAIMUKH	1500.0	0.0000	1.390	1522280	2283420	0.87

APPENDIX-C

Candidate Plants Data

C-1: Candidate thermal power plants

Name	Coal 5 - 500	Coal 7 -500	CCGT – 250	PFBC -450	IGCC - 400	Lignite -250	BIGCC 132
Fuel type used	Coal 5	Coal 7	Gas	Coal 6	Coal 6	Lignite	Wood
Fuel consumption rate unit	000'kg/ MWh	000'kg/ MWh	000'm3/ MWh	000'kg/ MWh	000'kg/ MWh	000'kg/ MWh	000'kg/ MWh
Fuel Consumption	0.7	0.6	0.2	0.51	0.51	0.7	0.51
Calorific value (kBtu/kg)	14	16.5	34.52	15.0	15.00	11.11	19.21
CO_2 emission factor (kg/MWh)	1026	1026	550	907	551	1078	71.64
SO_2 emission factor (kg/MWh)	6	6	0.4	0.255	0.235	14	0.918
NOx emission factor (kg/MWh)	2.5	2.5	1.64	0.6	0.6	1.64	0.6
Installed capacity (MW)	500	500	250	450	400	250	132
Earliest available year	2006	2006	2006	2006	2006	2006	2006
Availability	0.73	0.73	0.8	0.85	0.85	0.71	0.85
Unit depreciable Capital cost (k$)	450000	450000	175000	510000	500000	247500	132000
Unit non-depreciable Capital cost (k$)	50000	50000	19500	52500	50000	27500	14520
Heat rate at full load (Mcal/MWh)	2500	2400	2062	2100	2050	2100	2469
Operating cost (k$/MWh)	0.0012	0.0012	0.0008	0.0012	0.0013	0.0012	0.0174
Annual maintenance hour	864	864	1296	864	864	864	864
Fixed O&M cost (k$/Mwmonth)	2	2	1.67	2.2	2.32	2.0	5.4

C-2: Candidate hydro power plants

NAME	Capacity (MW)	No of Units	Availability factor	Unit Cost ($)	Operating cost (K$/ Mwhr)	Fixed O&M cost (K$/ Mw month)	Energy Season 1 (Mwhr)	Energy Season 2 (Mwhr)
DhauligangaII	70	3	0.9	77777	0	1.39	127333	190800
Kishanganga	110	3	0.9	122222	0	1.39	191600	287400
Kotlibhel	250	4	0.9	277777	0	1.39	541200	811800
UriII	70	9	0.9	77777	0	1.39	144800	217200
Bajoli Holi	100	2	0.9	111111	0	1.39	172200	258300
Luhri	425	1	0.9	472222	0	1.39	360000	540000
Jhangithopan	410	1	0.9	455555	0	1.39	619200	928800
Binoda	100	6	0.9	111111	0	1.39	116800	175200

Maslejghat	100	6	0.9	111111	0	1.39	74800	112200
Varandhghat	100	10	0.9	111111	0	1.39	74800	112200
Humbarli	100	4	0.9	111111	0	1.39	74800	112200
Dummugudum	90	4	0.9	100000	0	1.39	88400	132600
Bedthi	105	4	0.9	116666	0	1.39	84800	127200
Gundia High Head	120	2	0.9	133333	0	1.39	122000	183000
Mananthwadi	120	2	0.9	133333	0	1.39	163200	244800
Bhawanikattalai	90	1	0.9	100000	0	1.39	136000	204000
PandiarPunnapuzha	100	1	0.9	111111	0	1.39	163600	245400
Kadwan	90	5	0.9	100000	0	1.39	60400	90600
Kanhar	100	3	0.9	111111	0	1.39	50000	75000
Hirakud-B	102	4	0.9	113333	0	1.39	45200	67800
Teesta St-II	100	8	0.9	111111	0	1.39	172000	258000
Lohit	500	6	0.9	555555	0	1.39	580800	871200
Middle Siang	250	4	0.9	277777	0	1.39	192000	288000
Sisiri	110	2	0.9	122222	0	1.39	97000	292800
Umangot comb St1	150	1	0.9	166666	0	1.39	108000	162000
Barak	90	1	0.9	100000	0	1.39	158800	238200
Kirthai	120	2	0.9	133333	0	1.39	211600	317400
KirthaiII	120	3	0.9	133333	0	1.39	152800	229200
Khab-ii	105	4	0.9	116666	0	1.39	154400	231600
Sone	100	1	0.9	111111	0	1.39	79200	118800
Singareddy	100	2	0.9	111111	0	1.39	68000	102000
Lowerjurala	160	1	0.9	177777	0	1.39	121600	182400
Kerala Bhawani	150	1	0.9	166666	0	1.39	168000	252000
Sankhii	186	1	0.9	206666	0	1.39	96400	144600
Lower SiangSt1	100	4	0.9	133333	0	1.39	111200	166800
Lower SiangSt2	100	4	0.9	133333	0	1.39	111200	166800
Lower SiangSt3	100	4	0.9	133333	0	1.39	111200	166800
Lower SiangSt4	100	4	0.9	133333	0	1.39	111200	166800
Nuukcharoong	60	1	0.9	66666	0	1.39	87600	131400
Dibang st1	250	6	0.9	333333	0	1.39	230400	345600
Dibang st2	250	6	0.9	333333	0	1.39	230400	345600
Dibang st3	250	6	0.9	333333	0	1.39	230400	345600
Dibang st4	250	6	0.9	333333	0	1.39	230400	345600
Upper Siang1	250	10	0.9	333333	0	1.39	324800	487200
Upper Siang2	250	10	0.9	333333	0	1.39	324800	487200
Upper Siang3	250	10	0.9	333333	0	1.39	324800	487200
Upper Siang4	250	10	0.9	333333	0	1.39	324800	487200
UpperSiang st 5	250	4	0.9	333333	0	1.39	324800	487200
Uttarnchal combined	40	12	0.9	44444	0	1.39	84500	126600
Maharastra combd	65	4	0.9	72222	0	1.39	52400	78600

APPENDIX- D

DSM Data

D-1: Technical data and cost characteristics of appliances in residential sector

Existing appliances to be replaced				Efficient appliances considered		
Type of appliances	No. of appliances in year 2003 (Thousands)	Cost in US $	Life in years	Type of appliances	Cost in US $	Life in years
40W GLS	45,500	0.244	0.5	9W CFL	9.44	5
60W GLS	1,06,190	0.244	0.5	11W CFL	9.66	5
100W GLS	1,36,530	0.266	0.5	20W CFL	12.11	5

D-2: Technical data and cost characteristics of agricultural pumps

Number of agricultural pumps in 2003 (Thousands)	Type of rectification	Saving in power (KW) Per pump	Life in years	Cost in US $
15,225	Complete rectification	1.5	20	333.34
	Partial rectification	0.8	8	66.66

D-3: Penetration rates in percentage for considered DSM options

Year	DSM 1	DSM 2	DSM 3	DSM 4	DSM 5
2006	8.8	8.8	8.8	8.8	16.0
2007	10.0	10.0	10.0	10.0	18.0
2008	12.5	12.5	12.5	12.5	22.0
2009	15.0	15.0	15.0	15.0	26.0
2010	17.5	17.5	17.5	17.5	30.0
2011	20.0	20.0	20.0	20.0	34.0
2012	22.5	22.5	22.5	22.5	38.0
2013	25.0	25.0	25.0	25.0	42.0
2014	26.3	26.3	26.3	26.3	44.0
2015	27.5	27.5	27.5	27.5	46.0
2016	28.8	28.8	28.8	28.8	48.0
2017	30.0	30.0	30.0	30.0	50.0
2018	32.5	32.5	32.5	32.5	52.0
2019	35.0	35.0	35.0	35.0	54.0
2020	37.5	37.5	37.5	37.5	56.0
2021	40.0	40.0	40.0	40.0	58.0
2022	42.5	42.5	42.5	42.5	60.0
2023	45.0	45.0	45.0	45.0	62.0
2024	47.5	47.5	47.5	47.5	64.0
2025	50.0	50.0	50.0	50.0	66.0

D-4: Normalized chronological load curve for considered DSM options

Block	*DSM 1/ DSM2*		*DSM 3*		*DSM 4/ DSM 5*	
	Season 1	*Season 2*	*Season 1*	*Season 2*	*Season 1*	*Season 2*
1	0.027565	0.027731	0.006125	0.006162	0.275424	0.59322
2	0.027107	0.027277	0.006024	0.006061	0.275424	0.59322
3	0.026409	0.026985	0.005869	0.005997	0.275424	0.625
4	0.0267	0.027888	0.005933	0.006197	0.275424	0.741525
5	0.018813	0.020553	0.043897	0.047956	0.305085	0.987288
6	0.018505	0.021273	0.043178	0.049636	0.349576	1
7	0.01821	0.020761	0.04249	0.048442	0.349576	0.987288
8	0.018126	0.020918	0.042294	0.048809	0.349576	0.944915
9	0	0	0.022552	0.025345	0.275424	0.894068
10	0	0	0.022479	0.024126	0.275424	0.830508
11	0	0	0.022613	0.023573	0.275424	0.826271
12	0	0	0.02275	0.02386	0.275424	0.809322
13	0	0	0.023163	0.024017	0.305085	0.529661
14	0.8313	0.9394	0.8313	0.9394	0.305085	0.097458
15	0.9674	1	0.9674	1	0.038136	0.101695
16	1	0.9927	1	0.9927	0.038136	0.101695
17	0.9923	0.9864	0.9923	0.9864	0.038136	0.173729
18	0.9553	0.9642	0.9553	0.9642	0.245763	0.608051
19	0.8964	0.9113	0.8964	0.9113	0.245763	0.601695
20	0.027885	0.028317	0.006197	0.006293	0.245763	0.59322

Appendix-E

Emission Targets of Annex–B Countries

Party	Quantified emission Limitation (Percentage of base year)
Australia	108
Austria	92
Belgium	92
Bulgaria	92
Canada	94
Croatia	95
Czech Republic	92
Denmark	92
Estonia	92
European Community	92
Finland	92
France	92
Germany	92
Greece	92
Hungary	94
Iceland	110
Ireland	92
Italy	94
Japan	92
Latvia	92
Liechtenstein	92
Lithuania	92
Luxembourg	92
Monaco	92
Netherlands	92
New Zealand	100
Norway	101
Poland	94
Portugal	92
Romania	92
Russian Federation	100
Slovakia	92
Slovenia	92
Spain	92
Sweden	92
Switzerland	92
Ukraine	100
United Kingdom of Great Britain and Northern Ireland	97
United States of America	93